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Bureau of
Air Regulation

April 25, 1995

Mr. Clair Fancy
Bureau Chief
Federal Department of Environmental Protection
2600 Blairstone Road
Tallahassee, FL 32399-2400

Dear Mr. Fancy:

Enclosed please find six (6) signed Applications to Amend FSD Permit for Osceola Power Limited Partnership, located in Pahokee, Florida, together with a check in the amount of $6,750.00 for modification of air permit application.

Please feel free to contact me at (407)996-9072 if everything is not in order.

Thank you for your attention to the above.

Sincerely yours,

Gus Cepero
Vice President

Encl.
GC/mlh

316 ROYAL POINCIANA PLAZA P.O. BOX 1059 PALM BEACH, FL 33480 407-655-6303 FAX 407-659-3206

KBN

Letter of Transmittal

Date: 04/21/95

Project No.: 14380-0200

To: Mr. Gus Cepero
Osceola Corporation
6 miles south of South Bay on Hwy 27
P.O. Box 86
South Bay FL 33493

Re: Osceola Power Limited Partnership

The following items are being sent to you: ☒ *with this letter* ☐ *under separate cover*

Copies	*Description*
10	Application to Amend PSD Permit

These are transmitted:

☒ *As requested*

☐ *For review*

☐ *For review and comment*

☐ *For approval*

☐ *For your information*

☒ *For submittal*

Remarks: Please sign 6 copies and send for delivery to Clair Fancy at FDEP in Tallahassee.

Sender: David A. Buff/lcb

Copy to: Curt Staley (U.S. Generating)

KBN ENGINEERING AND APPLIED SCIENCES, INC.

XXXXX/# (04/95)

6241 Northwest 23rd Street,
Suite 500
Gainesville, Florida 32653-1500
904-336-5600 FAX 904-336-6603

5405 West Cypress Street,
Suite 215
Tampa, Florida 33607
813-287-1717 FAX 813-287-1716

1801 Clint Moore Road, Suite 105
Boca Raton, Florida 33487
407-994-9910
FAX 407-994-9393

7785 Baymeadows Way,
Suite 105
Jacksonville, Florida 32256
904-739-5600 FAX 904-739-7777

1616 'P' Street N.W., Suite 450
Washington, D.C. 20036
202-462-1100
FAX 202-462-2270

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7/9/03

APPLICATION TO AMEND
PSD PERMIT
FOR
OSCEOLA POWER
LIMITED PARTNERSHIP

PAHOKEE, FLORIDA
APRIL 1995

Prepared For:

Osceola Power Limited Partnership
P.O. Box 86
South Bay, Florida 33493

Prepared By:

KBN Engineering and Applied Sciences, Inc.
6241 NW 23rd Street
Gainesville, Florida 32653-1500

April 1995
14380C

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Department of Environmental Protection

PART A

DIVISION OF AIR RESOURCES MANAGEMENT

APPLICATION FOR AIR PERMIT - LONG FORM

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

I. APPLICATION INFORMATION

This section of the Application for Air Permit form provides general information on the scope of this application, the purpose for which this application is being submitted, and the nature of any construction or modification activities proposed as a part of this application. This section also includes information on the owner of the facility (or the responsible official in the case of a Title V source) and the necessary statements for the applicant and professional engineer, where required, to sign and date for formal submittal of the Application for Air Permit to the Department. If the application form is submitted to the Department on diskette, this section of the Application for Air Permit must also be submitted in hard-copy form.

Identification of Facility Addressed in This Application

Enter the name of the corporation, business, governmental entity, or individual that has ownership or control of the facility; the facility name, if any; and a brief reference to the facility's physical location. If known, also enter the ARMS or AIRS facility identification number. This information is intended to give a quick reference, on the first page of the application form, to the facility addressed in this application. Elsewhere in the form, numbered data fields are provided for entry of the facility data in computer-input format.

Osceola Power Limited Partnership **Pahokee, Florida** **50 PMB500331**

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	4-26-95
2. Permit Number:	AC50-269980
3. PSD Number (if applicable):	
4. Siting Number (if applicable):	

Owner/Authorized Representative or Responsible Official

1. Name and Title of Owner/Authorized Representative or Responsible Official:

Gus Cepero, Authorized Representative

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

Organization/Firm: **Osceola Power Limited Partnership**
Street Address: **P.O. Box 86**
City: **South Bay** State: **FL** Zip Code: **33493**

3. Owner/Authorized Representative or Responsible Official Telephone Numbers:

Telephone: **(407) 996-9072** Fax:

4. Owner/Authorized Representative or Responsible Official Statement:

I, the undersigned, am the owner or authorized representative of the facility (non-Title V source) addressed in this Application for Air Permit or the responsible official, as defined in Chapter 62-213, F.A.C., of the Title V source addressed in this application, whichever is applicable. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. Further, I agree to operate and maintain the air pollutant emissions units and air pollution control equipment described in this application 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. If the purpose of this application is to obtain an air operation permit or operation permit revision for one or more emissions units which have undergone construction or modification, I 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. 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 source.*

Signature
Date 4/25/95

* Attach letter of authorization if not currently on file.

Scope of Application

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

Emissions Unit ID / Description of Emissions Unit

001 No. 2 Fuel Oil Storage Tank
002 Boiler No.1 fired by Biomass/No.2 oil/coal with ESP, SNCR and Hg control
003 Boiler No.2 fired by Biomass/No.2 oil/coal with ESP, SNCR and Hg control
004 Fugitive Emissions from Biomass/Coal/Ash Handling

Purpose of Application and Category

Check one (except as otherwise indicated):

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

This Application for Air Permit is submitted to obtain:

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

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

Current construction permit number: ______________________________

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

Operation permit to be renewed: ______________________________

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

Current construction permit number: ______________________________

Operation permit to be renewed: ______________________________

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

Operation permit to be revised/corrected: ______________________________

____

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

Operation permit to be revised: ______________________________

Reason for revision: ______________________________

____

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

This Application for Air Permit is submitted to obtain:

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

Current operation/construction permit number(s):

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

Operation permit to be renewed:

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

Operation permit to be revised:

Reason for revision:

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

This Application for Air Permit is submitted to obtain:

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

Current operation permit number(s), if any:
AC 50-219795

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

Current operation permit number(s):

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

Application Processing Fee

Check one:

[ ] Attached - Amount: $ **$ 6,250.00** [ ] Not Applicable.

Construction/Modification Information

1. Description of Proposed Project or Alterations:

This application proposes revisions to the current construction permit. Construction of a 74 MW Biomass fired cogeneration facility.

2. Projected or Actual Date of Commencement of Construction (DD-MON-YYYY):

29 Jun 1994

3. Projected Date of Completion of Construction (DD-MON-YYYY):

1 Jun 1996

Professional Engineer Certification

1. Professional Engineer Name: **David A. Buff**
Registration Number: **19011**

2. Professional Engineer Mailing Address:
Organization/Firm: **KBN Engineering & Applied Sciences**
Street Address: **6241 NW 23rd St., Suite #500**
City: **Gainesville** State: **FL** Zip Code: **32605-1500**

3. Professional Engineer Telephone Numbers:
Telephone: **(904) 336-5600** Fax: **(904) 336-6603**

4. Professional Engineer's Statement:

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

(1) To the best of my knowledge, there is reasonable assurance (a) 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; or (b) for any application for a Title V source air operation permit, 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;

(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; and

(3) For any application for an air construction permit for one or more proposed new or modified emissions units, 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.

David A. Buff 4/21/95

Signature, (seal) Date

* Attach any exception to certification statement.

Application Contact

1. Name and Title of Application Contact:
   David A. Buff,

2. Application Contact Mailing Address:

   Organization/Firm: **KBN Engineering & Applied Sciences**
   Street Address: **6241 NW 23rd St., Suite #500**
   City: **Gainesville** State: **FL** Zip Code: **32605-1500**

3. Application Contact Telephone Numbers:

   Telephone: **(904) 336-5600** Fax: **(904) 336-6603**

Application Comment

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Name, Location, and Type

1. Facility Owner or Operator: Osceola Power Limited Partnership

2. Facility Name: Osceola Power L.P.

3. Facility Identification Number: 50 PMB500331 [ ] Unknown

4. Facility Location Information:
Facility Street Address: U.S. Highway 98 and Hatton Highway
City: Pahokee County: Palm Beach Zip Code: 33476

5. Facility UTM Coordinates:
Zone: 17 East (km): 544.2 North (km): 2968.0

6. Facility Latitude/Longitude:
Latitude (DD/MM/SS): 26/49/45 Longitude: (DD/MM/SS): 80/33/00

7. Governmental Facility Code: O	8. Facility Status Code: C	9. Relocatable Facility? [ ] Yes [x] No	10. Facility Major Group SIC Code: 49

11. Facility Comment:
74 MW Electric Cogen using biomass, oil or coal

Facility Contact

1. Name and Title of Facility Contact:
S. Donald Schaberg, P.E.

2. Facility Contact Mailing Address:
Organization/Firm: Osceola Power Limited Partnership
Street Address: P.O. Box 679
City: Pahokee State: FL Zip Code: 33476

3. Facility Contact Telephone Numbers:
Telephone: (407) 924-7156 Fax: (407) 924-7428

Facility Regulatory Classifications

1. Small Business Stationary Source?
[ ] Yes [x] No [ ] Unknown

2. Title V Source?
[x] Yes [ ] No

3. Synthetic Non-Title V Source?
[ ] Yes, [x] No

4. Major Source of Pollutants Other than Hazardous Air Pollutants (HAPs)?
[x] Yes [ ] No

5. Synthetic Minor Source of Pollutants Other than HAPs?
[ ] Yes [x] No

6. Major Source of HAPs?
[x] Yes [ ] No [ ] Possible

7. Synthetic Minor Source of HAPs?
[ ] Yes [x] No

8. One or More Emissions Units Subject to NSPS?
[x] Yes [ ] No

9. One or More Emissions Units Subject to NESHAP?
[ ] Yes [x] No

10. Title V Source by EPA Designation?
[ ] Yes [x] No

11. Facility Regulatory Classifications Comment:

B. FACILITY REGULATIONS

Depending on the application category, this subsection of the Application for Air Permit form provides either a brief analysis or detailed listing of federal, state, and local regulations applicable to the facility as a whole. (Regulations applicable to individual emissions units within the facility are addressed in Subsection III-B of the form.)

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

Not Applicable

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

62-210.300

C. FACILITY POLLUTANT INFORMATION

This subsection of the Application for Air Permit form allows for the reporting of potential and estimated emissions of selected pollutants on a facility-wide basis. It must be completed for each pollutant for which the applicant proposes to establish a facility-wide emissions cap and for each pollutant for which emissions are not reported at the emissions-unit level.

Facility Pollutant Information: Pollutant _____ of _____

1. Pollutant Emitted:		
2. Estimated Emissions:		(tons/yr)
3. Requested Emissions Cap:	(lb/hr)	(tons/yr)
4. Basis for Emissions Cap Code:		
5. Facility Pollutant Comment: **Not Applicable**		

Facility Pollutant Information Pollutant _____ of _____

1. Pollutant Emitted:		
2. Estimated Emissions:		(tons/yr)
3. Requested Emissions Cap:	(lb/hr)	(tons/yr)
4. Basis for Emissions Cap Code:		
5. Facility Pollutant Comment:		

Facility Pollutant Information: Pollutant _____ of _____

1. Pollutant Emitted:

2. Estimated Emissions: (tons/yr)

3. Requested Emissions Cap: (lb/hr) (tons/yr)

4. Basis for Emissions Cap Code:

5. Facility Pollutant Comment:

Facility Pollutant Information: Pollutant _____ of _____

1. Pollutant Emitted:

2. Estimated Emissions: (tons/yr)

3. Requested Emissions Cap: (lb/hr) (tons/yr)

4. Basis for Emissions Cap Code:

5. Facility Pollutant Comment:

D. FACILITY SUPPLEMENTAL INFORMATION

This subsection of the Application for Air Permit form provides supplemental information related to the facility as a whole. (Supplemental information related to individual eissions units within the facility is provided in Subsection III-I of the form.) Supplemental information must be submitted as an attachment to each copy of the form, in hard-copy or computer-readable form.

Supplemental Requirements for All Applications

1. Area Map Showing Facility Location:
   [X] Attached, Document ID: PART B
   [ ] Not Applicable [ ] Waiver Requested

2. Facility Plot Plan:
   [X] Attached, Document ID: PART B
   [ ] Not Applicable [ ] Waiver Requested

3. Process Flow Diagram(s):
   [X] Attached, Document ID(s): PART B
   [ ] Not Applicable [ ] Waiver Requested

4. Precautions to Prevent Emissions of Unconfined Particulate Matter:
   [X] Attached, Document ID: PART B
   [ ] Not Applicable

5. Fugitive Emissions Identification:
   [X] Attached, Document ID: PART B
   [ ] Not Applicable

6. Supplemental Information for Construction Permit Application:
   [X] Attached, Document ID: PART B
   [ ] Not Applicable

Additional Supplemental Requirements for Category I Applications Only

7. List of Insignificant Activities:
   [ ] Attached, Document ID: ____________________
   [X] Not Applicable

8. List of Equipment/Activities Regulated under Title VI:
   [ ] Attached, Document ID: ____________________
   [ ] Equipment/Activities Onsite but Not Required to be Individually Listed
   [X] Not Applicable

9. Alternative Methods of Operation:
[ ] Attached, Document ID: ________________
[x] Not Applicable

10. Alternative Modes of Operation (Emissions Trading):
[ ] Attached, Document ID: ________________
[x] Not Applicable

11. Enhanced Monitoring Plan:
[ ] Attached, Document ID: ________________
[x] Not Applicable

12. Risk Management Plan Verification:

[ ] Plan Submitted to Implementing Agency - Verification Attached
Attached, Document ID: ________________

[ ] Plan to be Submitted to Implementing Agency by Required Date

[x] Not Applicable

13. Compliance Report and Plan
[ ] Attached, Document ID: ________________
[x] Not Applicable

14. Compliance Statement (Hard-copy Required)
[ ] Attached, Document ID: ________________
[x] Not Applicable

EMISSIONS
UNIT 1

No.2 Fuel Oil Tank

Emissions Unit Information Section 1 **of** 4

III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through I 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

This subsection of the Application for Air Permit form provides general information on the emissions unit addressed in this Emissions Unit Information Section, including information on the type, control equipment, operating capacity, and operating schedule of the emissions unit..

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, an individually-regulated emission point (stack or vent) serving a single process or production unit, or activity, which also has other individually-regulated emission points.

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, a collectively-regulated 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.

Emissions Unit Description and Status

1. Description of Emissions Unit Addressed in This Section:

No. 2 Fuel Oil Storage Tank

2. ARMS Identification Number: [x] No Corresponding ID [ ] Unknown

3. Emissions Unit Status Code: A	4. Acid Rain Unit? [ ] Yes [x] No	5. Emissions Unit Major Group SIC Code: 49

6. Initial Startup Date (DD-MON-YYYY):

7. Long-term Reserve Shutdown Date (DD-MON-YYYY):

8. Package Unit:
Manufacturer: Model Number:

9. Generator Nameplate Rating: MW

10. Incinerator Information:

Dwell Temperature: °F
Dwell Time: seconds
Incinerator Afterburner Temperature: °F

11. Emissions Unit Comment:

Emissions Unit Control Equipment Information

A.

1. Description:

2. Control Device or Method Code:

B.

1. Description:

2. Control Device or Method Code:

C.

1. Description:

2. Control Device or Method Code:

Emissions Unit Operating Capacity

1. Maximum Heat Input Rate:
mmBtu/hr

2. Maximum Incineration Rate:
lbs/hr tons/day

3. Maximum Process or Throughput Rate:
13,992,754 gal/yr

4. Maximum Production Rate:

5. Operating Capacity Comment:
No. 2 Fuel Oil

Emissions Unit Operating Schedule

1. Requested Maximum Operating Schedule:

24 hours/day, 7 days/week,

52 weeks/yr 8760 hours/yr

B. EMISSIONS UNIT REGULATIONS

Depending on the application category, this subsection of the Application for Air Permit form provides either a brief analysis or detailed listing of all federal, state, and local regulations applicable to the emissions unit addressed in this Emissions Unit Information Section.

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

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

40 CFR 60, Subpart Kb

C. EMISSION POINT (STACK/VENT) INFORMATION

This subsection of the application for Air Permit form provides information about the emission point associated with the emissions unit addressed in this Emissions Unit Information Section. An emission point is typically a stack or vent but can be any identifiable location at which air pollutants, including fugitive emissions, are discharged into the atmosphere.

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram:

No. 2 fuel oil tank

2. Emission Point Type Code:

[x] 1 [ ] 2 [ ] 3 [ ] 4

3. Descriptions of Emissions Points Comprising this Emissions Unit:

4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:

5. Discharge Type Code:

[ ] D [x] F [ ] H [ ] P
[ ] R [ ] V [ ] W

Source Information Section 1 of 4 **No.2 Fuel Oil Tank**

6. Stack Height: ft

7. Exit Diameter: ft

8. Exit Temperature: °F

9. Actual Volumetric Flow Rate: acfm

10. Percent Water Vapor: %

11. Maximum Dry Standard Flow Rate: dscfm

12. Nonstack Emission Point Height: **24** ft

13. Emission Point UTM Coordinates:

Zone: East (km): North (km):

14. Emission Point Comment:

Nonstack emission point height of 24 feet corresponds to tank shell height.

D. SEGMENT (PROCESS/FUEL) INFORMATION

For the emissions unit addressed in this Emissions Unit Information Section, a separate set of segment data (Fields 1-10) must be completed for each segment required to be reported and for each alternative operating method or mode (emissions trading scenario) under Chapter 62-213, F.A.C., for which the maximum hourly or annual segment-related rate would vary. A segment is a material handling, process, fuel burning, volatile organic liquid storage, production, or other such operation to which emissions of the unit are directly related. See instructions for further details on this subsection of the Application for Air Permit.

Segment Description and Rate Information: Segment 1 of 2

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode): **No. 2 fuel oil: Breathing Loss**	
2. Source Classification Code (SCC): **40301019**	
3. SCC Units: **1,000 gallons storage capacity**	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:
6. Estimated Annual Activity Factor: **50**	
7. Maximum Percent Sulfur:	8. Maximum Percent Ash:
9. Million Btu per SCC Unit:	
10. Segment Comment: **50,000 gallon tank**	

Segment Description and Rate Information: Segment 2 of 2

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode): No. 2 fuel oil: Working Loss	
2. Source Classification Code (SCC): 40301021	
3. SCC Units: 1,000 gallons throughput	
4. Maximum Hourly Rate:	5. Maximum Annual Rate: 13,992.754
6. Estimated Annual Activity Factor:	
7. Maximum Percent Sulfur:	8. Maximum Percent Ash:
9. Million Btu per SCC Unit:	
10. Segment Comment:	

E. POLLUTANT INFORMATION

For the emissions unit addressed in this Emissions Unit Information Section, a separate set of pollutant information must be completed for each pollutant required to be reported. See instructions for further details on this subsection of the Application for Air Permit.

Pollutant Potential/Estimated Emissions: Pollutant 1 of 1

1. Pollutant Emitted: VOC

2. Total Percent Efficiency of Control: %

3. Primary Control Device Code: 095

4. Secondary Control Device Code:

5. Potential Emissions: 0.016 lbs/hr 0.0693 tons/yr

6. Synthetically Limited? [ ] Yes [x] No

7. Range of Estimated Fugitive/Other Emissions:

[ ] 1 [ ] 2 [ ] 3 ________ to ________ tons/yr

8. Emission Factor:

Reference: AP-42, Section 12, Storage of Organic Liquids

9. Emissions Method Code (check one):

[ ] 1 [ ] 2 [x] 3 [ ] 4 [ ] 5

10. Calculation of Emissions:

See Attachment

11. Pollutant Potential/Estimated Emissions Comment:

Emissions estimated using the TANKS computer program (Version 2.0)

Emissions Unit Information Section 1 **of** 4

Allowable Emissions (Pollutant identification on front page)

A.

1. Basis for Allowable Emissions Code:		
2. Future Effective Date of Allowable Emissions:		
3. Requested Allowable Emissions and Units:		
4. Equivalent Allowable Emissions:	lbs/hr	tons/yr
5. Method of Compliance:		
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):		

B.

1. Basis for Allowable Emissions Code:		
2. Future Effective Date of Allowable Emissions:		
3. Requested Allowable Emissions and Units:		
4. Equivalent Allowable Emissions:	lbs/hr	tons/yr
5. Method of Compliance:		
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):		

F. VISIBLE EMISSIONS INFORMATION

This subsection of the Application for Air Permit form must be completed for only those emissions units which are subject to a visible emissions limitation. The intent of this subsection of the form is to identify each activity associated with the emissions unit addressed in this section for which a separate opacity limitation would be applicable. Visible emission subtype codes for each such activity are listed in the instructions for Field 1. Most emissions units will be subject to a "subtype VE" limit only.

Visible Emissions Limitations: Visible Emissions Limitation _____ of _____

1. Visible Emissions Subtype: N/A

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:

Emissions Unit Information Section 1 **of** 4 **No.2 Fuel Oil Tank**

Visible Emissions Limitations: 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:

Visible Emissions Limitations: 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:

G. CONTINUOUS MONITOR INFORMATION

This subsection of the Application for Air Permit form must be completed for only those emissions units which are required by rule or permit to install and operate one or more continuous emission, opacity, flow, or other type monitors. A separate set of continuous monitor information (fields 1-6) must be completed for each monitoring system required.

Continuous Monitoring System Continuous Monitor _____ of _____

1.	Parameter Code: N/A
2.	CMS Requirement: [ ] Rule [ ] Other
3.	Monitor Information: Monitor Manufacturer: Model Number: Serial Number:
4.	Installation Date (DD-MON-YYYY):
5.	Performance Specification Test Date (DD-MON-YYYY):
6.	Continuous Monitor Comment:

Continuous Monitoring System Continuous Monitor _____ of _____

1. Parameter Code:

2. CMS Requirement: [ ] Rule [ ] Other

3. Monitor Information:

Monitor Manufacturer:
Model Number: Serial Number:

4. Installation Date (DD-MON-YYYY):

5. Performance Specification Test Date (DD-MON-YYYY):

6. Continuous Monitor Comment:

Continuous Monitoring System Continuous Monitor _____ of _____

1. Parameter Code:

2. CMS Requirement: [ ] Rule [ ] Other

3. Monitor Information:

Monitor Manufacturer:
Model Number: Serial Number:

4. Installation Date (DD-MON-YYYY):

5. Performance Specification Test Date (DD-MON-YYYY):

6. Continuous Monitor Comment:

H. PREVENTION OF SIGNIFICANT DETERIORATION (PSD) INCREMENT TRACKING INFORMATION

This subsection of the Application for Air Permit form must be completed for all applications, not just those undergoing prevention-of-significant-deterioration (PSD) review persuant to Rule 62-212.400, F.A.C. The intent of this subsection is to make a preliminary determination as to whether the emissions unit addressed in this Emissons Unit Information Section consumes PSD increment. PSD increment is consumed (or expanded) as a result of emission increases (decreases) occurring after pollutant-specific baseline dates. Pollutants for which baseline dates have been established are sulfur dioxide, particulate matter, and nitrogen dioxide.

PSD Increment Consumption Determination

1. Increment Consuming for Particulate Matter or Sulfur Dioxide?

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

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

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

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

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

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

2. Increment Consuming for Nitrogen Dioxide?

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

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

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

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

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

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

3.	Increment Consuming/Expanding Code:			
	PM	[ ] C	[ ] E	[ ] Unknown
	SO_2	[ ] C	[ ] E	[ ] Unknown
	NO_2	[ ] C	[ ] E	[ ] Unknown
4.	Baseline Emissions:			
	PM	lbs/hr		tons/yr
	SO_2	lbs/hr		tons/yr
	NO_2			tons/yr
5.	PSD Comment: Not Applicable			

I. EMISSIONS UNIT SUPPLEMENTAL INFORMATION

This subsection of the Application for Air Permit form provides supplemental information related to the emissions unit addressed in this Emissions Unit Information Section. Supplemental information must be submitted as an attachment to each copy of the form, in hard-copy or computer-readable form.

Supplemental Requirements for All Applications

1. Process Flow Diagram

[ ] Attached, Document ID: ______
[x] Not Applicable [ ] Waiver Requested

2. Fuel Analysis or Specification

[ ] Attached, Document ID: ______
[x] Not Applicable [ ] Waiver Requested

3. Detailed Description of Control Equipment

[ ] Attached, Document ID: ______
[x] Not Applicable [ ] Waiver Requested

4. Description of Stack Sampling Facilities

[ ] Attached, Document ID: ______
[x] Not Applicable [ ] Waiver Requested

5. Compliance Test Report

[ ] Attached, Document ID: ______ [X] Not Applicable
[ ] Previously Submitted, Date: ______

6. Procedures for Startup and Shutdown

[ ] Attached, Document ID: ______ [X] Not Applicable

7. Operation and Maintenance Plan

[ ] Attached, Document ID: ______ [X] Not Applicable

8. Supplemental Information for Construction Permit Application

[X] Attached, Document ID: PART B [ ] Not Applicable

9. Other Information Required by Rule or Statute

[X] Attached, Document ID: PART B [ ] Not Applicable

Additional Supplemental Requirements for Category I Applications Only

10. Alternative Methods of Operation

[ ] Attached, Document ID: ____________ [ ] Not Applicable

11. Alternative Modes of Operation (Emissions Trading)

[ ] Attached, Document ID: ____________ [ ] Not Applicable

12. Enhanced Monitoring Plan

[ ] Attached, Document ID: ____________ [ ] Not Applicable

13. Identification of Additional Applicable Requirements

[ ] Attached, Document ID: ____________ [ ] Not Applicable

14. Acid Rain Permit Application

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

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

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

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

[ ] Not Applicable

EMISSIONS
UNIT 2

Emissions Unit Information Section 2 **of** 4

III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through I 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

This subsection of the Application for Air Permit form provides general information on the emissions unit addressed in this Emissions Unit Information Section, including information on the type, control equipment, operating capacity, and operating schedule of the emissions unit..

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, an individually-regulated emission point (stack or vent) serving a single process or production unit, or activity, which also has other individually-regulated emission points.

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, a collectively-regulated 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.

Emissions Unit Description and Status

1. Description of Emissions Unit Addressed in This Section:

Boiler No.1 fired by biomass/No.2 oil/ Coal with ESP SNCR and Hg control systems.

2. ARMS Identification Number: [ ] No Corresponding ID [ ] Unknown

001

3. Emissions Unit Status Code: **C**

4. Acid Rain Unit? [x] Yes [ ] No

5. Emissions Unit Major Group SIC Code: **49**

6. Initial Startup Date (DD-MON-YYYY):

7. Long-term Reserve Shutdown Date (DD-MON-YYYY):

8. Package Unit:
Manufacturer: Model Number:

9. Generator Nameplate Rating: **74** MW

10. Incinerator Information:

Dwell Temperature: °F
Dwell Time: seconds
Incinerator Afterburner Temperature: °F

11. Emissions Unit Comment:

74 MW gross generating capacity for entire facility

Emissions Unit Control Equipment Information

A.

1. Description:

   ESP - Electrostatic Precipitator

2. Control Device or Method Code: **010**

B.

1. Description:

   Urea Injection

2. Control Device or Method Code: **032**

C.

1. Description:

   Activated Carbon injection system.

2. Control Device or Method Code: **099**

Emissions Unit Operating Capacity

1. Maximum Heat Input Rate: 760 mmBtu/hr

2. Maximum Incineration Rate: lbs/hr tons/day

3. Maximum Process or Throughput Rate:

4. Maximum Production Rate:

5. Operating Capacity Comment:

Maximum heat input rates: Biomass - 760 MMBtu/hr; No.2 Fuel Oil - 600 MMBtu/hr; Coal - 530 MMBtu/hr

Emissions Unit Operating Schedule

1. Requested Maximum Operating Schedule:

24 hours/day, 7 days/week,

52 weeks/yr 8760 hours/yr

B. EMISSIONS UNIT REGULATIONS

Depending on the application category, this subsection of the Application for Air Permit form provides either a brief analysis or detailed listing of all federal, state, and local regulations applicable to the emissions unit addressed in this Emissions Unit Information Section.

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

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

40 CFR 60,Subpart Da

C. EMISSION POINT (STACK/VENT) INFORMATION

This subsection of the application for Air Permit form provides information about the emission point associated with the emissions unit addressed in this Emissions Unit Information Section. An emission point is typically a stack or vent but can be any identifiable location at which air pollutants, including fugitive emissions, are discharged into the atmosphere.

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram:

BLR 1

2. Emission Point Type Code:

[x] 1 [ ] 2 [ ] 3 [ ] 4

3. Descriptions of Emissions Points Comprising this Emissions Unit:

4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:

5. Discharge Type Code:

[ ] D [ ] F [ ] H [ ] P
[ ] R [x] V [ ] W

Source Information Section 2 of 4 **Boiler No.1**

6. Stack Height: **200** ft

7. Exit Diameter: **8** ft

8. Exit Temperature: **295** °F

9. Actual Volumetric Flow Rate: **246,000** acfm

10. Percent Water Vapor: %

11. Maximum Dry Standard Flow Rate: dscfm

12. Nonstack Emission Point Height: ft

13. Emission Point UTM Coordinates:

Zone: **17** East (km): **544.2** North (km): **2968.0**

14. Emission Point Comment:

Stack parameters based on biomass.

D. SEGMENT (PROCESS/FUEL) INFORMATION

For the emissions unit addressed in this Emissions Unit Information Section, a separate set of segment data (Fields 1-10) must be completed for each segment required to be reported and for each alternative operating method or mode (emissions trading scenario) under Chapter 62-213, F.A.C., for which the maximum hourly or annual segment-related rate would vary. A segment is a material handling, process, fuel burning, volatile organic liquid storage, production, or other such operation to which emissions of the unit are directly related. See instructions for further details on this subsection of the Application for Air Permit.

Segment Description and Rate Information: Segment 1 of 4

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode):
Bagasse

2. Source Classification Code (SCC): 10101101

3. SCC Units:
tons burned

4. Maximum Hourly Rate: 89.412

5. Maximum Annual Rate: 783,144

6. Estimated Annual Activity Factor:

7. Maximum Percent Sulfur: 0.025

8. Maximum Percent Ash: 0.83

9. Million Btu per SCC Unit: 8.5

10. Segment Comment:
Total biomass both boilers = 965,647 TPY

Segment Description and Rate Information: Segment 2 of 4

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode):
Wood Fuel

2. Source Classification Code (SCC): 10100903

3. SCC Units: tons burned

4. Maximum Hourly Rate: 69.091	5. Maximum Annual Rate: 605,236

6. Estimated Annual Activity Factor:

7. Maximum Percent Sulfur: 0.025	8. Maximum Percent Ash: 3.2

9. Million Btu per SCC Unit: 11

10. Segment Comment:
Total biomass both boilers = 965,647 TPY

D. SEGMENT (PROCESS/FUEL) INFORMATION

For the emissions unit addressed in this Emissions Unit Information Section, a separate set of segment data (Fields 1-10) must be completed for each segment required to be reported and for each alternative operating method or mode (emissions trading scenario) under Chapter 62-213, F.A.C., for which the maximum hourly or annual segment-related rate would vary. A segment is a material handling, process, fuel burning, volatile organic liquid storage, production, or other such operation to which emissions of the unit are directly related. See instructions for further details on this subsection of the Application for Air Permit.

Segment Description and Rate Information: Segment 3 of 4

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode): **No.2 Fuel Oil**	
2. Source Classification Code (SCC): **10200505**	
3. SCC Units: **1,000 gal burned**	
4. Maximum Hourly Rate: **4.348**	5. Maximum Annual Rate: **13,992.754**
6. Estimated Annual Activity Factor:	
7. Maximum Percent Sulfur: **0.05**	8. Maximum Percent Ash:
9. Million Btu per SCC Unit: **138**	
10. Segment Comment: **Total No.2 Fuel Oil both boilers = 13,992,754 gal/yr. This represents 25% oil firing on a heat input basis.**	

Segment Description and Rate Information: Segment 4 of 4

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode): Butiminous Coal	
2. Source Classification Code (SCC): 10100204	
3. SCC Units: tons burned	
4. Maximum Hourly Rate: 22.084	5. Maximum Annual Rate: 18,221
6. Estimated Annual Activity Factor:	
7. Maximum Percent Sulfur: 0.7	8. Maximum Percent Ash: 3.7
9. Million Btu per SCC Unit: 24	
10. Segment Comment: Total coal both boilers = 18,221 TPY. This represents, 5.4% coal burning on a heat input basis.	

Boiler No.1
Hydrogen Chloride

Emissions Unit Information Section 2 of 4

E. POLLUTANT INFORMATION

For the emissions unit addressed in this Emissions Unit Information Section, a separate set of pollutant information must be completed for each pollutant required to be reported. See instructions for further details on this subsection of the Application for Air Permit.

Pollutant Potential/Estimated Emissions: Pollutant 1 of 18

1. Pollutant Emitted: HCL

2. Total Percent Efficiency of Control: %

3. Primary Control Device Code:

4. Secondary Control Device Code:

5. Potential Emissions: 41.9 lbs/hr 19.42 tons/yr

6. Synthetically Limited? [x] Yes [ ] No

7. Range of Estimated Fugitive/Other Emissions:

[ ] 1 [ ] 2 [ ] 3 ____________ to ____________ tons/yr

8. Emission Factor: 0.079 lb/MMBtu

Reference: See Part B

9. Emissions Method Code (check one):

[ ] 1 [ ] 2 [ ] 3 [ ] 4 [x] 5

10. Calculation of Emissions:

0.079 lb/MMBtu x 530 MMBtu/hr = 41.9 lb/hr

11. Pollutant Potential/Estimated Emissions Comment:

19.42 TPY total both boilers

Emissions Unit Information Section 2 of 4

Allowable Emissions (Pollutant identification on front page)

A.

1. Basis for Allowable Emissions Code:

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units:

4. Equivalent Allowable Emissions: lbs/hr tons/yr

5. Method of Compliance:

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):

B.

1. Basis for Allowable Emissions Code:

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units:

4. Equivalent Allowable Emissions: lbs/hr tons/yr

5. Method of Compliance:

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):

Boiler No.1
Acetaldehyde

E. POLLUTANT INFORMATION

For the emissions unit addressed in this Emissions Unit Information Section, a separate set of pollutant information must be completed for each pollutant required to be reported. See instructions for further details on this subsection of the Application for Air Permit.

Pollutant Potential/Estimated Emissions: Pollutant 2 of 18

1. Pollutant Emitted: **H001**

2. Total Percent Efficiency of Control: %

3. Primary Control Device Code:

4. Secondary Control Device Code:

5. Potential Emissions: **0.59** lbs/hr **2.58** tons/yr

6. Synthetically Limited? [x] Yes [ ] No

7. Range of Estimated Fugitive/Other Emissions:

[ ] 1 [ ] 2 [ ] 3 __________ to __________ tons/yr

8. Emission Factor: **0.00078 lb/MMBtu**

Reference: **See Part B**

9. Emissions Method Code (check one):

[ ] 1 [ ] 2 [ ] 3 [ ] 4 [ ] 5

10. Calculation of Emissions:

0.00078 lb/MMBtu x 760 MMBtu/hr = 0.59 lb/hr

11. Pollutant Potential/Estimated Emissions Comment:

3.20 TPY total for both boilers

Boiler No. 1
Acetaldehyde

Emissions Unit Information Section 2 of 4

Allowable Emissions (Pollutant identification on front page)

A.

1. Basis for Allowable Emissions Code:	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units:	
4. Equivalent Allowable Emissions: lbs/hr	tons/yr
5. Method of Compliance:	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):	

B.

1. Basis for Allowable Emissions Code:	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units:	
4. Equivalent Allowable Emissions: lbs/hr	tons/yr
5. Method of Compliance:	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):	

Emissions Unit Information Section 2 of 4

E. POLLUTANT INFORMATION

For the emissions unit addressed in this Emissions Unit Information Section, a separate set of pollutant information must be completed for each pollutant required to be reported. See instructions for further details on this subsection of the Application for Air Permit.

Pollutant Potential/Estimated Emissions: Pollutant 3 of 18

1. Pollutant Emitted: H017

2. Total Percent Efficiency of Control: %

3. Primary Control Device Code:

4. Secondary Control Device Code:

5. Potential Emissions: 0.99 lbs/hr 4.34 tons/yr

6. Synthetically Limited? [ ] Yes [ ] No

7. Range of Estimated Fugitive/Other Emissions:

[ ] 1 [ ] 2 [ ] 3 ____________ to ____________ tons/yr

8. Emission Factor: 0.0013 lb/MMBtu

Reference: See Part B

9. Emissions Method Code (check one):

[ ] 1 [ ] 2 [ ] 3 [ ] 4 [ ] 5

10. Calculation of Emissions:

0.0013 lb/MMBtu x 760 MMBtu/hr = 0.99 lb/hr

11. Pollutant Potential/Estimated Emissions Comment:

5.34 TPY total for both boilers.

Emissions Unit Information Section 2 of 4

Allowable Emissions (Pollutant identification on front page)

A.

1. Basis for Allowable Emissions Code:
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:
4. Equivalent Allowable Emissions: lbs/hr tons/yr
5. Method of Compliance:
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):

B.

1. Basis for Allowable Emissions Code:
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:
4. Equivalent Allowable Emissions: lbs/hr tons/yr
5. Method of Compliance:
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):

Emissions Unit Information Section 2 of 4

E. POLLUTANT INFORMATION

For the emissions unit addressed in this Emissions Unit Information Section, a separate set of pollutant information must be completed for each pollutant required to be reported. See instructions for further details on this subsection of the Application for Air Permit.

<u>Pollutant Potential/Estimated Emissions</u>: Pollutant 4 of 18

1. Pollutant Emitted: H038

2. Total Percent Efficiency of Control: %

3. Primary Control Device Code:

4. Secondary Control Device Code:

5. Potential Emissions: 0.7 lbs/hr 3.07 tons/yr

6. Synthetically Limited? [x] Yes [ ] No

7. Range of Estimated Fugitive/Other Emissions:

[ ] 1 [ ] 2 [ ] 3 ________ to ________ tons/yr

8. Emission Factor: 0.00092 lb/MMBtu

Reference: See Part B

9. Emissions Method Code (check one):

[ ] 1 [ ] 2 [x] 3 [ ] 4 [ ] 5

10. Calculation of Emissions:

0.00092 lb/MMBtu x 760 MMBtu/hr = 0.70 lb/hr

11. Pollutant Potential/Estimated Emissions Comment:

3.78 TPY total for both boilers

Boiler No. 1
Chlorine

Emissions Unit Information Section 2 of 4

Allowable Emissions (Pollutant identification on front page)

A.

1. Basis for Allowable Emissions Code:

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units:

4. Equivalent Allowable Emissions: lbs/hr tons/yr

5. Method of Compliance:

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):

B.

1. Basis for Allowable Emissions Code:

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units:

4. Equivalent Allowable Emissions: lbs/hr tons/yr

5. Method of Compliance:

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):

Boiler No.1
Formaldehyde

Emissions Unit Information Section 2 of 4

E. POLLUTANT INFORMATION

For the emissions unit addressed in this Emissions Unit Information Section, a separate set of pollutant information must be completed for each pollutant required to be reported. See instructions for further details on this subsection of the Application for Air Permit.

Pollutant Potential/Estimated Emissions: Pollutant 5 of 18

1. Pollutant Emitted: H095

2. Total Percent Efficiency of Control: %

3. Primary Control Device Code:

4. Secondary Control Device Code:

5. Potential Emissions: 0.99 lbs/hr 4.34 tons/yr

6. Synthetically Limited? [x] Yes [ ] No

7. Range of Estimated Fugitive/Other Emissions:

[ ] 1 [ ] 2 [ ] 3 ____________ to ____________ tons/yr

8. Emission Factor: 0.0013 lb/MMBtu

Reference: See Part B

9. Emissions Method Code (check one):

[ ] 1 [ ] 2 [ ] 3 [ ] 4 [x] 5

10. Calculation of Emissions:

0.0013 lb/MMBtu x 760 MMBtu/hr = 0.99 lb/hr

11. Pollutant Potential/Estimated Emissions Comment:

5.34 TPY total for both boilers

Emissions Unit Information Section 2 **of** 4

Allowable Emissions (Pollutant identification on front page)

A.

1. Basis for Allowable Emissions Code:

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units:

4. Equivalent Allowable Emissions: lbs/hr tons/yr

5. Method of Compliance:

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):

B.

1. Basis for Allowable Emissions Code:

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units:

4. Equivalent Allowable Emissions: lbs/hr tons/yr

5. Method of Compliance:

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):

E. POLLUTANT INFORMATION

For the emissions unit addressed in this Emissions Unit Information Section, a separate set of pollutant information must be completed for each pollutant required to be reported. See instructions for further details on this subsection of the Application for Air Permit.

Pollutant Potential/Estimated Emissions: Pollutant 6 of 18

1. Pollutant Emitted: H104

2. Total Percent Efficiency of Control: %

3. Primary Control Device Code:

4. Secondary Control Device Code:

5. Potential Emissions: 0.42 lbs/hr 1.84 tons/yr

6. Synthetically Limited? [x] Yes [ ] No

7. Range of Estimated Fugitive/Other Emissions:

[ ] 1 [ ] 2 [ ] 3 ________ to ________ tons/yr

8. Emission Factor: 0.00055 lb/MMBtu

Reference: See Part B

9. Emissions Method Code (check one):

[ ] 1 [ ] 2 [ ] 3 [ ] 4 [x] 5

10. Calculation of Emissions:

0.00055 lb/MMBtu x 760 MMBtu/hr = 0.42 lb/hr

11. Pollutant Potential/Estimated Emissions Comment:

2.26 TPY total for both boilers

Emissions Unit Information Section 2 of 4

Allowable Emissions (Pollutant identification on front page)

A.

1. Basis for Allowable Emissions Code:
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:
4. Equivalent Allowable Emissions: lbs/hr tons/yr
5. Method of Compliance:
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):

B.

1. Basis for Allowable Emissions Code:
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:
4. Equivalent Allowable Emissions: lbs/hr tons/yr
5. Method of Compliance:
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):

Emissions Unit Information Section 2 of 4

Boiler No.1
Methanol

E. POLLUTANT INFORMATION

For the emissions unit addressed in this Emissions Unit Information Section, a separate set of pollutant information must be completed for each pollutant required to be reported. See instructions for further details on this subsection of the Application for Air Permit.

Pollutant Potential/Estimated Emissions: Pollutant 7 of 18

1. Pollutant Emitted: H115	
2. Total Percent Efficiency of Control: %	
3. Primary Control Device Code:	
4. Secondary Control Device Code:	
5. Potential Emissions: 1.14 lbs/hr	4.99 tons/yr
6. Synthetically Limited? [x] Yes [ ] No	
7. Range of Estimated Fugitive/Other Emissions: [ ] 1 [ ] 2 [ ] 3 ________ to ________ tons/yr	
8. Emission Factor: 0.015 lb/MMBtu Reference: See Part B	
9. Emissions Method Code (check one): [ ] 1 [ ] 2 [ ] 3 [ ] 4 [x] 5	
10. Calculation of Emissions: **0.015 lb/MMBtu x 760 MMBtu/hr = 1.14 lb/hr**	
11. Pollutant Potential/Estimated Emissions Comment: 6.16 TPY total for both boilers	

Boiler No. 1
Methanol

Emissions Unit Information Section 2 of 4

Allowable Emissions (Pollutant identification on front page)

A.

1. Basis for Allowable Emissions Code:

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units:

4. Equivalent Allowable Emissions: lbs/hr tons/yr

5. Method of Compliance:

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):

B.

1. Basis for Allowable Emissions Code:

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units:

4. Equivalent Allowable Emissions: lbs/hr tons/yr

5. Method of Compliance:

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):

E. POLLUTANT INFORMATION

For the emissions unit addressed in this Emissions Unit Information Section, a separate set of pollutant information must be completed for each pollutant required to be reported. See instructions for further details on this subsection of the Application for Air Permit.

Pollutant Potential/Estimated Emissions: Pollutant 8 of 18

1. Pollutant Emitted: **H123**

2. Total Percent Efficiency of Control: %

3. Primary Control Device Code:

4. Secondary Control Device Code:

5. Potential Emissions: **0.65** lbs/hr **2.85** tons/yr

6. Synthetically Limited? [x] Yes [ ] No

7. Range of Estimated Fugitive/Other Emissions:

[ ] 1 [ ] 2 [ ] 3 ________ to ________ tons/yr

8. Emission Factor: **0.00086 lb/MMBtu**

Reference: **See Part B**

9. Emissions Method Code (check one):

[ ] 1 [ ] 2 [ ] 3 [ ] 4 [x] 5

10. Calculation of Emissions:

0.00086 lb/MMBtu x 760 MMBtu/hr = 0.65 lb/hr

11. Pollutant Potential/Estimated Emissions Comment:

3.53 TPY total for both boilers

Boiler No. 1
Methyl isobutyl ketone

Emissions Unit Information Section 2 of 4

Allowable Emissions (Pollutant identification on front page)

A.

1. Basis for Allowable Emissions Code:
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:
4. Equivalent Allowable Emissions: lbs/hr tons/yr
5. Method of Compliance:
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):

B.

1. Basis for Allowable Emissions Code:
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:
4. Equivalent Allowable Emissions: lbs/hr tons/yr
5. Method of Compliance:
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):

Boiler No.1
Methylene chloride

Emissions Unit Information Section 2 of 4

E. POLLUTANT INFORMATION

For the emissions unit addressed in this Emissions Unit Information Section, a separate set of pollutant information must be completed for each pollutant required to be reported. See instructions for further details on this subsection of the Application for Air Permit.

Pollutant Potential/Estimated Emissions: Pollutant 9 of 18

1. Pollutant Emitted: H128

2. Total Percent Efficiency of Control: %

3. Primary Control Device Code:

4. Secondary Control Device Code:

5. Potential Emissions: 1.14 lbs/hr 4.99 tons/yr

6. Synthetically Limited? [x] Yes [ ] No

7. Range of Estimated Fugitive/Other Emissions:

[ ] 1 [ ] 2 [ ] 3 ____________ to ____________ tons/yr

8. Emission Factor: 0.0015 lb/MMBtu

Reference: See Part B

9. Emissions Method Code (check one):

[ ] 1 [ ] 2 [ ] 3 [ ] 4 [x] 5

10. Calculation of Emissions:

0.0015 lb/MMBtu x 760 MMBtu/hr = 1.14 lb/hr

11. Pollutant Potential/Estimated Emissions Comment:

6.16 TPY total for both boilers

Boiler No. 1
Methylene chloride

Emissions Unit Information Section 2 of 4

Allowable Emissions (Pollutant identification on front page)

A.

1. Basis for Allowable Emissions Code:

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units:

4. Equivalent Allowable Emissions: lbs/hr tons/yr

5. Method of Compliance:

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):

B.

1. Basis for Allowable Emissions Code:

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units:

4. Equivalent Allowable Emissions: lbs/hr tons/yr

5. Method of Compliance:

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):

Emissions Unit Information Section 2 of 4

E. POLLUTANT INFORMATION

For the emissions unit addressed in this Emissions Unit Information Section, a separate set of pollutant information must be completed for each pollutant required to be reported. See instructions for further details on this subsection of the Application for Air Permit.

Pollutant Potential/Estimated Emissions: Pollutant 10 of 18

1. Pollutant Emitted: H132

2. Total Percent Efficiency of Control: %

3. Primary Control Device Code:

4. Secondary Control Device Code:

5. Potential Emissions: 0.45 lbs/hr 1.97 tons/yr

6. Synthetically Limited? [x] Yes [ ] No

7. Range of Estimated Fugitive/Other Emissions:

[ ] 1 [ ] 2 [ ] 3 ________ to ________ tons/yr

8. Emission Factor: 0.00059 lb/MMBtu

Reference: See Part B

9. Emissions Method Code (check one):

[ ] 1 [ ] 2 [ ] 3 [ ] 4 [x] 5

10. Calculation of Emissions:

0.00059 lb/MMBtu x 760 MMBtu/hr = 0.45 lb/hr

11. Pollutant Potential/Estimated Emissions Comment:

2.42 TPY total for both boilers

Emissions Unit Information Section 2 of 4

Allowable Emissions (Pollutant identification on front page)

A.

1. Basis for Allowable Emissions Code:

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units:

4. Equivalent Allowable Emissions: lbs/hr tons/yr

5. Method of Compliance:

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):

B.

1. Basis for Allowable Emissions Code:

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units:

4. Equivalent Allowable Emissions: lbs/hr tons/yr

5. Method of Compliance:

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):

E. POLLUTANT INFORMATION

For the emissions unit addressed in this Emissions Unit Information Section, a separate set of pollutant information must be completed for each pollutant required to be reported. See instructions for further details on this subsection of the Application for Air Permit.

Pollutant Potential/Estimated Emissions: Pollutant 11 of 18

1. Pollutant Emitted: TSP

2. Total Percent Efficiency of Control: 98 %

3. Primary Control Device Code: 010

4. Secondary Control Device Code:

5. Potential Emissions: 22.8 lbs/hr 99.86 tons/yr

6. Synthetically Limited? [x] Yes [ ] No

7. Range of Estimated Fugitive/Other Emissions:

[ ] 1 [ ] 2 [ ] 3 ________ to ________ tons/yr

8. Emission Factor: 0.03 lb/MMBtu

Reference: NSPS 40 CFR 60 Subpart Da

9. Emissions Method Code (check one):

[ ] 1 [ ] 2 [ ] 3 [ ] 4 [x] 5

10. Calculation of Emissions:

0.03 lb/MMBtu x 760 MMBtu/hr = 22.8 lb/hr

11. Pollutant Potential/Estimated Emissions Comment:

123.12 TPY total for both boilers

Emissions Unit Information Section 2 of 4

Allowable Emissions (Pollutant identification on front page)

A.

1. Basis for Allowable Emissions Code:
NSPS

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units:
0.03 lb/MMBtu

4. Equivalent Allowable Emissions: 22.8 lbs/hr 99.86 tons/yr

5. Method of Compliance:
Annual stack test using EPA Method 5

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):
Maximum lb/hr based on biomass firing.

B.

1. Basis for Allowable Emissions Code:

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units:

4. Equivalent Allowable Emissions: lbs/hr tons/yr

5. Method of Compliance:

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):

E. POLLUTANT INFORMATION

For the emissions unit addressed in this Emissions Unit Information Section, a separate set of pollutant information must be completed for each pollutant required to be reported. See instructions for further details on this subsection of the Application for Air Permit.

Pollutant Potential/Estimated Emissions: Pollutant 12 of 18

1. Pollutant Emitted: PM10

2. Total Percent Efficiency of Control: 98 %

3. Primary Control Device Code: 010

4. Secondary Control Device Code:

5. Potential Emissions: 22.8 lbs/hr 99.86 tons/yr

6. Synthetically Limited? [x] Yes [ ] No

7. Range of Estimated Fugitive/Other Emissions:

[ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/yr

8. Emission Factor: 0.03 lb/MMBtu

Reference: NSPS 40 CFR 60 Subpart Da

9. Emissions Method Code (check one):

[ ] 1 [ ] 2 [ ] 3 [ ] 4 [x] 5

10. Calculation of Emissions:

0.03 lb/MMBtu x 760 MMBtu/hr = 22.8 lb/hr

11. Pollutant Potential/Estimated Emissions Comment:

123.12 TPY total for both boilers

Emissions Unit Information Section 2 of 4

Allowable Emissions (Pollutant identification on front page)

A.

1. Basis for Allowable Emissions Code:
NSPS

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units:
0.03 lb/MMBtu

4. Equivalent Allowable Emissions: 22.8 lbs/hr 99.86 tons/yr

5. Method of Compliance:

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):
Maximum lb/hr based on biomass firing.

B.

1. Basis for Allowable Emissions Code:

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units:

4. Equivalent Allowable Emissions: lbs/hr tons/yr

5. Method of Compliance:

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):

E. POLLUTANT INFORMATION

For the emissions unit addressed in this Emissions Unit Information Section, a separate set of pollutant information must be completed for each pollutant required to be reported. See instructions for further details on this subsection of the Application for Air Permit.

Pollutant Potential/Estimated Emissions: Pollutant 13 of 18

1. Pollutant Emitted: SO2

2. Total Percent Efficiency of Control: %

3. Primary Control Device Code:

4. Secondary Control Device Code:

5. Potential Emissions: 636 lbs/hr 338 tons/yr

6. Synthetically Limited? [x] Yes [ ] No

7. Range of Estimated Fugitive/Other Emissions:

[ ] 1 [ ] 2 [ ] 3 __________ to __________ tons/yr

8. Emission Factor: 1.2 lb/MMBtu

Reference: Based on NSPS 40 CFR 60 Subpart Da

9. Emissions Method Code (check one):

[ ] 1 [ ] 2 [ ] 3 [ ] 4 [x] 5

10. Calculation of Emissions:

1.2 lb/MMBtu x 530 MMBtu/hr = 636.0 lb/hr

11. Pollutant Potential/Estimated Emissions Comment:

338.0 TPY total for both boilers

Emissions Unit Information Section 2 of 4

Allowable Emissions (Pollutant identification on front page)

A.

1. Basis for Allowable Emissions Code:
NSPS

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units:
1.2 lb/MMBtu

4. Equivalent Allowable Emissions: 636 lbs/hr 339 tons/yr

5. Method of Compliance:
Limit coal burning to 5.4%; fuel analysis, continous SO2 monitor

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):
Based on coal firing

B.

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: 30 lbs/hr 65.7 tons/yr

5. Method of Compliance:
Limit fuel oil burning to 25% for facility; 50% for any single boiler.

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):
Based on No.2 fuel oil firing and BACT.

Boiler No. 1
Sulfur Dioxide

Emissions Unit Information Section 2 of 4

Allowable Emissions (Pollutant identification on front page)

A.

1. Basis for Allowable Emissions Code:
   Other

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units:
   0.1 lb/MMBtu 24-hr avg; 0.02 lb/MMBtu, annual average

4. Equivalent Allowable Emissions: 76 lbs/hr 332.9 tons/yr

5. Method of Compliance:
   Continuous SO2 monitor

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):
   Based on bagasse firing and fuel sulfur content

B.

1. Basis for Allowable Emissions Code:

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units:

4. Equivalent Allowable Emissions: lbs/hr tons/yr

5. Method of Compliance:

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):

Emissions Unit Information Section 2 of 4

E. POLLUTANT INFORMATION

For the emissions unit addressed in this Emissions Unit Information Section, a separate set of pollutant information must be completed for each pollutant required to be reported. See instructions for further details on this subsection of the Application for Air Permit.

Pollutant Potential/Estimated Emissions: Pollutant 14 of 18

1. Pollutant Emitted: NOx

2. Total Percent Efficiency of Control: 40 %

3. Primary Control Device Code: 081

4. Secondary Control Device Code:

5. Potential Emissions: 88.2 lbs/hr 386.3 tons/yr

6. Synthetically Limited? [x] Yes [ ] No

7. Range of Estimated Fugitive/Other Emissions:

[ ] 1 [ ] 2 [ ] 3 ________ to ________ tons/yr

8. Emission Factor: 0.116 lb/MMBtu

Reference: Based on NOx control system

9. Emissions Method Code (check one):

[ ] 1 [x] 2 [ ] 3 [ ] 4 [ ] 5

10. Calculation of Emissions:

0.116 lb/MMBtu x 760 MMBtu/hr = 88.2 lb/hr

11. Pollutant Potential/Estimated Emissions Comment:

477.1 TPY total for both boilers

Emissions Unit Information Section 2 of 4

Allowable Emissions (Pollutant identification on front page)

A.

1. Basis for Allowable Emissions Code:
ESCPSD

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units:
0.116 lb/MMBtu

4. Equivalent Allowable Emissions: 88.2 lbs/hr 386.3 tons/yr

5. Method of Compliance:
Annual stack test using EPA Method 7 or 7E

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):
Based on biomass firing

B.

1. Basis for Allowable Emissions Code: ESCPSD

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units:
0.12 lb/MMBtu

4. Equivalent Allowable Emissions: 72 lbs/hr 157.7 tons/yr

5. Method of Compliance:
Limit fuel oil burning to 25% for entire facility;50% for any single boiler

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):
Based on No.2 fuel oil firing

Emissions Unit Information Section 2 of 4

Allowable Emissions (Pollutant identification on front page)

A.

1. Basis for Allowable Emissions Code: ESCPSD
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 0.15 lb/MMBtu
4. Equivalent Allowable Emissions: 79.5 lbs/hr 37.6 tons/yr
5. Method of Compliance: Limit coal burning to 5.4% entire facility; 10.8% for any single boiler
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode): Based on coal firing

B.

1. Basis for Allowable Emissions Code:
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:
4. Equivalent Allowable Emissions: lbs/hr tons/yr
5. Method of Compliance:
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):

Emissions Unit Information Section 2 of 4

Boiler No.1
Carbon Monoxide

E. POLLUTANT INFORMATION

For the emissions unit addressed in this Emissions Unit Information Section, a separate set of pollutant information must be completed for each pollutant required to be reported. See instructions for further details on this subsection of the Application for Air Permit.

Pollutant Potential/Estimated Emissions: Pollutant 15 of 18

1. Pollutant Emitted: CO

2. Total Percent Efficiency of Control: %

3. Primary Control Device Code:

4. Secondary Control Device Code:

5. Potential Emissions: 266 lbs/hr 1,165.1 tons/yr

6. Synthetically Limited? [x] Yes [ ] No

7. Range of Estimated Fugitive/Other Emissions:

[ ] 1 [ ] 2 [ ] 3 ________ to ________ tons/yr

8. Emission Factor: 0.35 lb/MMBtu

Reference: Based on boiler design

9. Emissions Method Code (check one):

[ ] 1 [x] 2 [ ] 3 [ ] 4 [ ] 5

10. Calculation of Emissions:

0.35 lb/MMBtu x 760 MMBtu/hr = 266 lb/hr

11. Pollutant Potential/Estimated Emissions Comment:

1,436.4 TPY total for both boilers

Emissions Unit Information Section 2 of 4

Allowable Emissions (Pollutant identification on front page)

A.

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: 266 lbs/hr 1,165.1 tons/yr

5. Method of Compliance:
Continous CO monitor

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):
Based on biomass firing

B.

1. Basis for Allowable Emissions Code: Other

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units:
0.2 lb/MMBtu

4. Equivalent Allowable Emissions: 120 lbs/hr 262.8 tons/yr

5. Method of Compliance:
Limit fuel burning to 25% entire facility; 50% for any single boiler

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):
Based on No.2 fuel oil firing

Emissions Unit Information Section 2 of 4

Allowable Emissions (Pollutant identification on front page)

A.

1. Basis for Allowable Emissions Code:
Other

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units:
0.2 lb/MMBtu

4. Equivalent Allowable Emissions: **106** lbs/hr **50.1** tons/yr

5. Method of Compliance:
Limit coal burning to 5.4% entire facility; 10.8% for any single boiler

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):
Based on coal firing

B.

1. Basis for Allowable Emissions Code:

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units:

4. Equivalent Allowable Emissions: lbs/hr tons/yr

5. Method of Compliance:

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):

E. POLLUTANT INFORMATION

For the emissions unit addressed in this Emissions Unit Information Section, a separate set of pollutant information must be completed for each pollutant required to be reported. See instructions for further details on this subsection of the Application for Air Permit.

Pollutant Potential/Estimated Emissions: Pollutant 16 of 18

1. Pollutant Emitted: VOC

2. Total Percent Efficiency of Control: %

3. Primary Control Device Code:

4. Secondary Control Device Code:

5. Potential Emissions: 45.6 lbs/hr 219.15 tons/yr

6. Synthetically Limited? [x] Yes [ ] No

7. Range of Estimated Fugitive/Other Emissions:

[ ] 1 [ ] 2 [ ] 3 ________ to ________ tons/yr

8. Emission Factor: 0.06 lb/MMBtu

Reference: Based on boiler design

9. Emissions Method Code (check one):

[ ] 1 [x] 2 [ ] 3 [ ] 4 [ ] 5

10. Calculation of Emissions:

0.06 lb/MMBtu x 760 MMBtu/hr = 45.6 lb/hr

11. Pollutant Potential/Estimated Emissions Comment:

Based on biomass firing

Emissions Unit Information Section 2 of 4

Allowable Emissions (Pollutant identification on front page)

A.

1. Basis for Allowable Emissions Code:
ESCNAA

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units: **0.04 lb/MMBtu Wood waste**
0.06 lb/MMBtu Bagasse

4. Equivalent Allowable Emissions: **45.6** lbs/hr **219.15** tons/yr

5. Method of Compliance:
Annual stack test using EPA Method 25 or 25A

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):
Based on biomass firing, 67% bagasse heat input - 33% wood waste heat input.

B.

1. Basis for Allowable Emissions Code: **ESCNAA**

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units:
0.03 lb/MMBtu

4. Equivalent Allowable Emissions: **18** lbs/hr **39.4** tons/yr

5. Method of Compliance:
Limit fuel burning to 25% entire facility; 50% for any single boiler

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):
Based on No.2 fuel oil firing

Boiler No. 1
Volatile Organic Compounds

Emissions Unit Information Section 2 of 4
Allowable Emissions (Pollutant identification on front page)

A.

1. Basis for Allowable Emissions Code:
   ESCNAA
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:
   0.03 lb/MMBtu
4. Equivalent Allowable Emissions: **15.9** lbs/hr **7.52** tons/yr
5. Method of Compliance:
   Limit coal burning to 5.4% entire facility; 10.8% for any single boiler
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):
   Based on coal firing

B.

1. Basis for Allowable Emissions Code:
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:
4. Equivalent Allowable Emissions: lbs/hr tons/yr
5. Method of Compliance:
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):

Emissions Unit Information Section 2 of 4

E. POLLUTANT INFORMATION

For the emissions unit addressed in this Emissions Unit Information Section, a separate set of pollutant information must be completed for each pollutant required to be reported. See instructions for further details on this subsection of the Application for Air Permit.

Pollutant Potential/Estimated Emissions: Pollutant 17 of 18

1. Pollutant Emitted: FL

2. Total Percent Efficiency of Control: %

3. Primary Control Device Code:

4. Secondary Control Device Code:

5. Potential Emissions: 12.7 lbs/hr 5.25 tons/yr

6. Synthetically Limited? [x] Yes [ ] No

7. Range of Estimated Fugitive/Other Emissions:

   [ ] 1 [ ] 2 [ ] 3 ____________ to ____________ tons/yr

8. Emission Factor: 0.024 lb/MMBtu

   Reference: See Part B

9. Emissions Method Code (check one):

   [ ] 1 [x] 2 [ ] 3 [ ] 4 [ ] 5

10. Calculation of Emissions:

    0.024 lb/MMBtu x 530 MMBtu/hr = 12.7 lb/hr

11. Pollutant Potential/Estimated Emissions Comment:

    Based on coal firing

Emissions Unit Information Section 2 of 4

Allowable Emissions (Pollutant identification on front page)

A.

1. Basis for Allowable Emissions Code:

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units:

4. Equivalent Allowable Emissions: lbs/hr tons/yr

5. Method of Compliance:

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):

B.

1. Basis for Allowable Emissions Code:

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units:

4. Equivalent Allowable Emissions: lbs/hr tons/yr

5. Method of Compliance:

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):

E. POLLUTANT INFORMATION

For the emissions unit addressed in this Emissions Unit Information Section, a separate set of pollutant information must be completed for each pollutant required to be reported. See instructions for further details on this subsection of the Application for Air Permit.

Pollutant Potential/Estimated Emissions: Pollutant 18 of 18

1. Pollutant Emitted: SAM

2. Total Percent Efficiency of Control: %

3. Primary Control Device Code:

4. Secondary Control Device Code:

5. Potential Emissions: 5.3 lbs/hr 6 tons/yr

6. Synthetically Limited? [x] Yes [ ] No

7. Range of Estimated Fugitive/Other Emissions:

[ ] 1 [ ] 2 [ ] 3 ________ to ________ tons/yr

8. Emission Factor: 0.01 lb/MMBtu

Reference: See Part B

9. Emissions Method Code (check one):

[ ] 1 [ ] 2 [x] 3 [ ] 4 [ ] 5

10. Calculation of Emissions:

0.010 lb/MMBtu x 530 MMBtu/hr = 5.3 lb/hr

11. Pollutant Potential/Estimated Emissions Comment:

Based on coal firing

Emissions Unit Information Section 2 of 4

Allowable Emissions (Pollutant identification on front page)

A.

1. Basis for Allowable Emissions Code:

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units:

4. Equivalent Allowable Emissions: lbs/hr tons/yr

5. Method of Compliance:

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):

B.

1. Basis for Allowable Emissions Code:

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units:

4. Equivalent Allowable Emissions: lbs/hr tons/yr

5. Method of Compliance:

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):

F. VISIBLE EMISSIONS INFORMATION

This subsection of the Application for Air Permit form must be completed for only those emissions units which are subject to a visible emissions limitation. The intent of this subsection of the form is to identify each activity associated with the emissions unit addressed in this section for which a separate opacity limitation would be applicable. Visible emission subtype codes for each such activity are listed in the instructions for Field 1. Most emissions units will be subject to a "subtype VE" limit only.

Visible Emissions Limitations: Visible Emissions Limitation 1 of 1

1.	Visible Emissions Subtype: VE
2.	Basis for Allowable Opacity: [X] Rule [ ] Other
3.	Requested Allowable Opacity Normal Conditions: 20 % Exceptional Conditions: 27 % Maximum Period of Excess Opacity Allowed: 6 min/hour
4.	Method of Compliance: EPA Method 9
5.	Visible Emissions Comment:

Visible Emissions Limitations: 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:

Visible Emissions Limitations: 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:

G. CONTINUOUS MONITOR INFORMATION

This subsection of the Application for Air Permit form must be completed for only those emissions units which are required by rule or permit to install and operate one or more continuous emission, opacity, flow, or other type monitors. A separate set of continuous monitor information (fields 1-6) must be completed for each monitoring system required.

Continuous Monitoring System Continuous Monitor 1 of 5

1. Parameter Code: **Opacity**

2. CMS Requirement: [x] Rule [ ] Other

3. Monitor Information:

   Monitor Manufacturer:
   Model Number: Serial Number:

4. Installation Date (DD-MON-YYYY):

5. Performance Specification Test Date (DD-MON-YYYY):

6. Continuous Monitor Comment:
   40 CFR 60, Subpart Da

Continuous Monitoring System Continuous Monitor 2 of 5

1. Parameter Code: NOx

2. CMS Requirement: [x] Rule [ ] Other

3. Monitor Information:

   Monitor Manufacturer:
   Model Number: Serial Number:

4. Installation Date (DD-MON-YYYY):

5. Performance Specification Test Date (DD-MON-YYYY):

6. Continuous Monitor Comment:

   40 CFR 60, Subpart Da

Continuous Monitoring System Continuous Monitor 3 of 5

1. Parameter Code: SO2

2. CMS Requirement: [ ] Rule [x] Other

3. Monitor Information:

   Monitor Manufacturer:
   Model Number: Serial Number:

4. Installation Date (DD-MON-YYYY):

5. Performance Specification Test Date (DD-MON-YYYY):

6. Continuous Monitor Comment:

   40 CFR 60, Subpart Da

G. CONTINUOUS MONITOR INFORMATION

This subsection of the Application for Air Permit form must be completed for only those emissions units which are required by rule or permit to install and operate one or more continuous emission, opacity, flow, or other type monitors. A separate set of continuous monitor information (fields 1-6) must be completed for each monitoring system required.

Continuous Monitoring System Continuous Monitor 4 of 5

1.	Parameter Code: CO
2.	CMS Requirement: [ ] Rule [x] Other
3.	Monitor Information: Monitor Manufacturer: Model Number: Serial Number:
4.	Installation Date (DD-MON-YYYY):
5.	Performance Specification Test Date (DD-MON-YYYY):
6.	Continuous Monitor Comment: 40 CFR 60, Subpart Da

Continuous Monitoring System Continuous Monitor 5 of 5

1. Parameter Code: O2

2. CMS Requirement: [ ] Rule [x] Other

3. Monitor Information:

   Monitor Manufacturer:
   Model Number: Serial Number:

4. Installation Date (DD-MON-YYYY):

5. Performance Specification Test Date (DD-MON-YYYY):

6. Continuous Monitor Comment:

   40 CFR 60, Subpart Da

Continuous Monitoring System Continuous Monitor _____ of 5

1. Parameter Code:

2. CMS Requirement: [ ] Rule [ ] Other

3. Monitor Information:

   Monitor Manufacturer:
   Model Number: Serial Number:

4. Installation Date (DD-MON-YYYY):

5. Performance Specification Test Date (DD-MON-YYYY):

6. Continuous Monitor Comment:

H. PREVENTION OF SIGNIFICANT DETERIORATION (PSD) INCREMENT TRACKING INFORMATION

This subsection of the Application for Air Permit form must be completed for all applications, not just those undergoing prevention-of-significant-deterioration (PSD) review persuant to Rule 62-212.400, F.A.C. The intent of this subsection is to make a preliminary determination as to whether the emissions unit addressed in this Emissons Unit Information Section consumes PSD increment. PSD increment is consumed (or expanded) as a result of emission increases (decreases) occurring after pollutant-specific baseline dates. Pollutants for which baseline dates have been established are sulfur dioxide, particulate matter, and nitrogen dioxide.

PSD Increment Consumption Determination

1. Increment Consuming for Particulate Matter or Sulfur Dioxide?

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

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

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

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

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

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

2. Increment Consuming for Nitrogen Dioxide?

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

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

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

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

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

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

3.	Increment Consuming/Expanding Code:			
	PM	[x] C	[ ] E	[ ] Unknown
	SO_2	[x] C	[ ] E	[ ] Unknown
	NO_2	[x] C	[ ] E	[ ] Unknown
4.	Baseline Emissions:			
	PM	lbs/hr		tons/yr
	SO_2	lbs/hr		tons/yr
	NO_2			tons/yr
5.	PSD Comment:			

I. EMISSIONS UNIT SUPPLEMENTAL INFORMATION

This subsection of the Application for Air Permit form provides supplemental information related to the emissions unit addressed in this Emissions Unit Information Section. Supplemental information must be submitted as an attachment to each copy of the form, in hard-copy or computer-readable form.

Supplemental Requirements for All Applications

1. Process Flow Diagram

[x] Attached, Document ID: PART B
[ ] Not Applicable [ ] Waiver Requested

2. Fuel Analysis or Specification

[x] Attached, Document ID: PART B
[ ] Not Applicable [ ] Waiver Requested

3. Detailed Description of Control Equipment

[x] Attached, Document ID: PART B
[ ] 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: ____________ [x] Not Applicable
[ ] Previously Submitted, Date: ____________

6. Procedures for Startup and Shutdown

[ ] Attached, Document ID: ____________ [x] Not Applicable

7. Operation and Maintenance Plan

[ ] Attached, Document ID: ____________ [x] Not Applicable

8. Supplemental Information for Construction Permit Application

[x] Attached, Document ID: PART B [ ] Not Applicable

9. Other Information Required by Rule or Statute

[x] Attached, Document ID: PART B [ ] Not Applicable

Additional Supplemental Requirements for Category I Applications Only

10. Alternative Methods of Operation

[ ] Attached, Document ID: ____________ [ ] Not Applicable

11. Alternative Modes of Operation (Emissions Trading)

[ ] Attached, Document ID: ____________ [ ] Not Applicable

12. Enhanced Monitoring Plan

[ ] Attached, Document ID: ____________ [ ] Not Applicable

13. Identification of Additional Applicable Requirements

[ ] Attached, Document ID: ____________ [ ] Not Applicable

14. Acid Rain Permit Application

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

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

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

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

[ ] Not Applicable

EMISSIONS
UNIT 3

Emissions Unit Information Section 3 **of** 4

III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through I 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

This subsection of the Application for Air Permit form provides general information on the emissions unit addressed in this Emissions Unit Information Section, including information on the type, control equipment, operating capacity, and operating schedule of the emissions unit..

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, an individually-regulated emission point (stack or vent) serving a single process or production unit, or activity, which also has other individually-regulated emission points.

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, a collectively-regulated 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.

Emissions Unit Description and Status

1. Description of Emissions Unit Addressed in This Section:

Boiler No.2 fired by biomass/No.2 oil/ Coal with ESP SNCR and Hg control systems.

2. ARMS Identification Number: [ ] No Corresponding ID [ ] Unknown

001

3. Emissions Unit Status Code: **C**

4. Acid Rain Unit? [x] Yes [ ] No

5. Emissions Unit Major Group SIC Code: **49**

6. Initial Startup Date (DD-MON-YYYY):

7. Long-term Reserve Shutdown Date (DD-MON-YYYY):

8. Package Unit:
Manufacturer: Model Number:

9. Generator Nameplate Rating: **74** MW

10. Incinerator Information:

Dwell Temperature: °F
Dwell Time: seconds
Incinerator Afterburner Temperature: °F

11. Emissions Unit Comment:

74 MW gross generating capacity for entire facility

Emissions Unit Control Equipment Information

A.

1. Description:

ESP - Electrostatic Precipitator

2. Control Device or Method Code: **010**

B.

1. Description:

Urea Injection

2. Control Device or Method Code: **032**

C.

1. Description:

Activated Carbon injection system.

2. Control Device or Method Code: **099**

Emissions Unit Operating Capacity

1. Maximum Heat Input Rate: 760 mmBtu/hr

2. Maximum Incineration Rate: lbs/hr tons/day

3. Maximum Process or Throughput Rate:

4. Maximum Production Rate:

5. Operating Capacity Comment:

Maximum heat input rates: Biomass - 760 MMBtu/hr; No.2 Fuel Oil - 600 MMBtu/hr; Cool - 530 MMBtu/hr

Emissions Unit Operating Schedule

1. Requested Maximum Operating Schedule:

24 hours/day, 7 days/week,

52 weeks/yr 8760 hours/yr

B. EMISSIONS UNIT REGULATIONS

Depending on the application category, this subsection of the Application for Air Permit form provides either a brief analysis or detailed listing of all federal, state, and local regulations applicable to the emissions unit addressed in this Emissions Unit Information Section.

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

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

40 CFR 60, Subpart Da

C. EMISSION POINT (STACK/VENT) INFORMATION

This subsection of the application for Air Permit form provides information about the emission point associated with the emissions unit addressed in this Emissions Unit Information Section. An emission point is typically a stack or vent but can be any identifiable location at which air pollutants, including fugitive emissions, are discharged into the atmosphere.

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram:

   BLR 2

2. Emission Point Type Code:

   [x] 1 [ ] 2 [ ] 3 [ ] 4

3. Descriptions of Emissions Points Comprising this Emissions Unit:

4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:

5. Discharge Type Code:

   [ ] D [ ] F [ ] H [ ] P
   [ ] R [x] V [ ] W

Source Information Section 3 of 4 **Boiler No.2**

6. Stack Height:	**200**	ft
7. Exit Diameter:	**8**	ft
8. Exit Temperature:	**295**	°F
9. Actual Volumetric Flow Rate:	**246,000**	acfm
10. Percent Water Vapor:		%
11. Maximum Dry Standard Flow Rate:		dscfm
12. Nonstack Emission Point Height:		ft

13. Emission Point UTM Coordinates:

Zone: **17** East (km): **544.2** North (km): **2968.0**

14. Emission Point Comment:

Stack parameters based on biomass.

D. SEGMENT (PROCESS/FUEL) INFORMATION

For the emissions unit addressed in this Emissions Unit Information Section, a separate set of segment data (Fields 1-10) must be completed for each segment required to be reported and for each alternative operating method or mode (emissions trading scenario) under Chapter 62-213, F.A.C., for which the maximum hourly or annual segment-related rate would vary. A segment is a material handling, process, fuel burning, volatile organic liquid storage, production, or other such operation to which emissions of the unit are directly related. See instructions for further details on this subsection of the Application for Air Permit.

Segment Description and Rate Information: Segment 1 of 4

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode): **Bagasse**	
2. Source Classification Code (SCC): **10101101**	
3. SCC Units: **tons burned**	
4. Maximum Hourly Rate: **89.412**	5. Maximum Annual Rate: **783,144**
6. Estimated Annual Activity Factor:	
7. Maximum Percent Sulfur: **0.025**	8. Maximum Percent Ash: **0.83**
9. Million Btu per SCC Unit: **8.5**	
10. Segment Comment: **total biomass both boilers = 965,647 TPY**	

Emissions Unit Information Section 3 of 4 **Boiler No.2**

Segment Description and Rate Information: Segment 2 of 4

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode):
Wood Fuel

2. Source Classification Code (SCC): **10100903**

3. SCC Units: **tons burned**

4. Maximum Hourly Rate: **69.091**

5. Maximum Annual Rate: **605,236**

6. Estimated Annual Activity Factor:

7. Maximum Percent Sulfur: **0.025**

8. Maximum Percent Ash: **3.2**

9. Million Btu per SCC Unit: **11**

10. Segment Comment:
Total biomass both boilers = 965,647 TPY

D. SEGMENT (PROCESS/FUEL) INFORMATION

For the emissions unit addressed in this Emissions Unit Information Section, a separate set of segment data (Fields 1-10) must be completed for each segment required to be reported and for each alternative operating method or mode (emissions trading scenario) under Chapter 62-213, F.A.C., for which the maximum hourly or annual segment-related rate would vary. A segment is a material handling, process, fuel burning, volatile organic liquid storage, production, or other such operation to which emissions of the unit are directly related. See instructions for further details on this subsection of the Application for Air Permit.

Segment Description and Rate Information: Segment 3 of 4

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode):
   No.2 Fuel Oil

2. Source Classification Code (SCC): 10200505

3. SCC Units:
   1,000 gal burned

4. Maximum Hourly Rate: 4.348

5. Maximum Annual Rate: 13,992.754

6. Estimated Annual Activity Factor:

7. Maximum Percent Sulfur: 0.05

8. Maximum Percent Ash:

9. Million Btu per SCC Unit: 138

10. Segment Comment:
    Total No.2 Fuel Oil both boilers = 13,992,754 gal/yr. This represents 25% oil firing on a heat input basis.

Segment Description and Rate Information: Segment 4 of 4

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode):
Butiminous Coal

2. Source Classification Code (SCC): 10100204

3. SCC Units: tons burned

4. Maximum Hourly Rate: 22.084

5. Maximum Annual Rate: 18,221

6. Estimated Annual Activity Factor:

7. Maximum Percent Sulfur: 0.7

8. Maximum Percent Ash: 3.7

9. Million Btu per SCC Unit: 24

10. Segment Comment:
Total coal both boilers = 18,221 TPY. This represents 5.4% coal burning on a heat input basis.

Boiler No.2
Hydrogen Chloride

Emissions Unit Information Section 3 of 4

E. POLLUTANT INFORMATION

For the emissions unit addressed in this Emissions Unit Information Section, a separate set of pollutant information must be completed for each pollutant required to be reported. See instructions for further details on this subsection of the Application for Air Permit.

Pollutant Potential/Estimated Emissions: Pollutant 1 of 18

1. Pollutant Emitted: HCL

2. Total Percent Efficiency of Control: %

3. Primary Control Device Code:

4. Secondary Control Device Code:

5. Potential Emissions: 41.9 lbs/hr 19.42 tons/yr

6. Synthetically Limited? [x] Yes [ ] No

7. Range of Estimated Fugitive/Other Emissions:

[ ] 1 [ ] 2 [ ] 3 ________ to ________ tons/yr

8. Emission Factor: 0.079 lb/MMBtu

Reference: See Part B

9. Emissions Method Code (check one):

[ ] 1 [ ] 2 [ ] 3 [ ] 4 [x] 5

10. Calculation of Emissions:

0.079 lb/MMBtu x 530 MMBtu/hr = 41.9 lb/hr

11. Pollutant Potential/Estimated Emissions Comment:

19.42 TPY total for both boilers

Boiler No. 2
Hydrogen Chloride

Emissions Unit Information Section 3 of 4

Allowable Emissions (Pollutant identification on front page)

A.

1. Basis for Allowable Emissions Code:
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:
4. Equivalent Allowable Emissions: lbs/hr tons/yr
5. Method of Compliance:
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):

B.

1. Basis for Allowable Emissions Code:
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:
4. Equivalent Allowable Emissions: lbs/hr tons/yr
5. Method of Compliance:
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):

E. POLLUTANT INFORMATION

For the emissions unit addressed in this Emissions Unit Information Section, a separate set of pollutant information must be completed for each pollutant required to be reported. See instructions for further details on this subsection of the Application for Air Permit.

Pollutant Potential/Estimated Emissions: Pollutant 2 of 18

1. Pollutant Emitted: **H001**

2. Total Percent Efficiency of Control: %

3. Primary Control Device Code:

4. Secondary Control Device Code:

5. Potential Emissions: **0.59** lbs/hr **2.58** tons/yr

6. Synthetically Limited? [x] Yes [ ] No

7. Range of Estimated Fugitive/Other Emissions:

[ ] 1 [ ] 2 [ ] 3 ________ to ________ tons/yr

8. Emission Factor: **0.00078 lb/MMBtu**

Reference: **See Part B**

9. Emissions Method Code (check one):

[ ] 1 [ ] 2 [ ] 3 [ ] 4 [x] 5

10. Calculation of Emissions:

0.00078 lb/MMBtu x 760 MMBtu/hr = 0.59 lb/hr

11. Pollutant Potential/Estimated Emissions Comment:

3.20 TPY total for both boilers

Boiler No. 2
Acetaldehyde

Emissions Unit Information Section 3 **of** 4

Allowable Emissions (Pollutant identification on front page)

A.

1. Basis for Allowable Emissions Code:
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:
4. Equivalent Allowable Emissions: lbs/hr tons/yr
5. Method of Compliance:
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):

B.

1. Basis for Allowable Emissions Code:
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:
4. Equivalent Allowable Emissions: lbs/hr tons/yr
5. Method of Compliance:
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):

Emissions Unit Information Section 3 **of** 4

E. POLLUTANT INFORMATION

For the emissions unit addressed in this Emissions Unit Information Section, a separate set of pollutant information must be completed for each pollutant required to be reported. See instructions for further details on this subsection of the Application for Air Permit.

Pollutant Potential/Estimated Emissions: Pollutant 3 of 18

1. Pollutant Emitted: **H017**

2. Total Percent Efficiency of Control: %

3. Primary Control Device Code:

4. Secondary Control Device Code:

5. Potential Emissions: **0.99** lbs/hr **4.34** tons/yr

6. Synthetically Limited? [x] Yes [ ] No

7. Range of Estimated Fugitive/Other Emissions:

[ ] 1 [ ] 2 [ ] 3 __________ to __________ tons/yr

8. Emission Factor: **0.0013 lb/MMBtu**

Reference: **See Part B**

9. Emissions Method Code (check one):

[ ] 1 [ ] 2 [ ] 3 [ ] 4 [x] 5

10. Calculation of Emissions:

0.0013 lb/MMBtu x 760 MMBtu/hr = 0.99 lb/hr

11. Pollutant Potential/Estimated Emissions Comment:

5.34 TPY total for both boilers

Boiler No. 2
Benzene

Emissions Unit Information Section 3 **of** 4

Allowable Emissions (Pollutant identification on front page)

A.

1. Basis for Allowable Emissions Code:

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units:

4. Equivalent Allowable Emissions: lbs/hr tons/yr

5. Method of Compliance:

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):

B.

1. Basis for Allowable Emissions Code:

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units:

4. Equivalent Allowable Emissions: lbs/hr tons/yr

5. Method of Compliance:

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):

Emissions Unit Information Section 3 of 4

Boiler No.2
Chlorine

E. POLLUTANT INFORMATION

For the emissions unit addressed in this Emissions Unit Information Section, a separate set of pollutant information must be completed for each pollutant required to be reported. See instructions for further details on this subsection of the Application for Air Permit.

Pollutant Potential/Estimated Emissions: Pollutant 4 of 18

1. Pollutant Emitted: **H038**

2. Total Percent Efficiency of Control: %

3. Primary Control Device Code:

4. Secondary Control Device Code:

5. Potential Emissions: **0.7** lbs/hr **3.07** tons/yr

6. Synthetically Limited? [x] Yes [ ] No

7. Range of Estimated Fugitive/Other Emissions:

[ ] 1 [ ] 2 [ ] 3 ________ to ________ tons/yr

8. Emission Factor: **0.00092 lb/MMBtu**

Reference: **See Part B**

9. Emissions Method Code (check one):

[ ] 1 [ ] 2 [x] 3 [ ] 4 [ ] 5

10. Calculation of Emissions:

0.00092 lb/MMBtu x 760 MMBtu/hr = 0.70 lb/hr

11. Pollutant Potential/Estimated Emissions Comment:

3.78 TPY total for both boilers

Emissions Unit Information Section 3 **of** 4

Allowable Emissions (Pollutant identification on front page)

A.

1. Basis for Allowable Emissions Code:

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units:

4. Equivalent Allowable Emissions: lbs/hr tons/yr

5. Method of Compliance:

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):

B.

1. Basis for Allowable Emissions Code:

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units:

4. Equivalent Allowable Emissions: lbs/hr tons/yr

5. Method of Compliance:

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):

Boiler No.2
Formaldehyde

Emissions Unit Information Section 3 of 4

E. POLLUTANT INFORMATION

For the emissions unit addressed in this Emissions Unit Information Section, a separate set of pollutant information must be completed for each pollutant required to be reported. See instructions for further details on this subsection of the Application for Air Permit.

Pollutant Potential/Estimated Emissions: Pollutant 5 of 18

1. Pollutant Emitted: H095

2. Total Percent Efficiency of Control: %

3. Primary Control Device Code:

4. Secondary Control Device Code:

5. Potential Emissions: 0.99 lbs/hr 4.34 tons/yr

6. Synthetically Limited? [x] Yes [ ] No

7. Range of Estimated Fugitive/Other Emissions:

[ ] 1 [ ] 2 [ ] 3 ____________ to ____________ tons/yr

8. Emission Factor: 0.0013 lb/MMBtu

Reference: See Part B

9. Emissions Method Code (check one):

[ ] 1 [ ] 2 [ ] 3 [ ] 4 [x] 5

10. Calculation of Emissions:

0.0013 lb/MMBtu x 760 MMBtu/hr = 0.99 lb/hr

11. Pollutant Potential/Estimated Emissions Comment:

5.34 TPY total for both boilers

Emissions Unit Information Section 3 of 4

Allowable Emissions (Pollutant identification on front page)

A.

1. Basis for Allowable Emissions Code:

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units:

4. Equivalent Allowable Emissions: lbs/hr tons/yr

5. Method of Compliance:

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):

B.

1. Basis for Allowable Emissions Code:

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units:

4. Equivalent Allowable Emissions: lbs/hr tons/yr

5. Method of Compliance:

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):

Boiler No.2
Hexane

Emissions Unit Information Section 3 **of** 4

E. POLLUTANT INFORMATION

For the emissions unit addressed in this Emissions Unit Information Section, a separate set of pollutant information must be completed for each pollutant required to be reported. See instructions for further details on this subsection of the Application for Air Permit.

Pollutant Potential/Estimated Emissions: Pollutant 6 of 18

1. Pollutant Emitted: H104

2. Total Percent Efficiency of Control: %

3. Primary Control Device Code:

4. Secondary Control Device Code:

5. Potential Emissions: 0.42 lbs/hr 1.84 tons/yr

6. Synthetically Limited? [x] Yes [ ] No

7. Range of Estimated Fugitive/Other Emissions:

[ ] 1 [ ] 2 [ ] 3 ____ to ____ tons/yr

8. Emission Factor: 0.00055 lb/MMBtu

Reference: See Part B

9. Emissions Method Code (check one):

[ ] 1 [ ] 2 [ ] 3 [ ] 4 [x] 5

10. Calculation of Emissions:

0.00055 lb/MMBtu x 760 MMBtu/hr = 0.42 lb/hr

11. Pollutant Potential/Estimated Emissions Comment:

2.26 TPY total for both boilers

Emissions Unit Information Section 3 of 4

Allowable Emissions (Pollutant identification on front page)

A.

1. Basis for Allowable Emissions Code:
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:
4. Equivalent Allowable Emissions: lbs/hr tons/yr
5. Method of Compliance:
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):

B.

1. Basis for Allowable Emissions Code:
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:
4. Equivalent Allowable Emissions: lbs/hr tons/yr
5. Method of Compliance:
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):

E. POLLUTANT INFORMATION

For the emissions unit addressed in this Emissions Unit Information Section, a separate set of pollutant information must be completed for each pollutant required to be reported. See instructions for further details on this subsection of the Application for Air Permit.

Pollutant Potential/Estimated Emissions: Pollutant 7 of 18

1. Pollutant Emitted: **H115**

2. Total Percent Efficiency of Control: %

3. Primary Control Device Code:

4. Secondary Control Device Code:

5. Potential Emissions: **1.14** lbs/hr **4.99** tons/yr

6. Synthetically Limited? [x] Yes [ ] No

7. Range of Estimated Fugitive/Other Emissions:

[ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/yr

8. Emission Factor: **0.015 lb/MMBtu**

Reference: **See Part B**

9. Emissions Method Code (check one):

[ ] 1 [ ] 2 [ ] 3 [ ] 4 [x] 5

10. Calculation of Emissions:

0.015 lb/MMBtu x 760 MMBtu/hr = 1.14 lb/hr

11. Pollutant Potential/Estimated Emissions Comment:

6.16 TPY total for both boilers

Emissions Unit Information Section 3 of 4

Allowable Emissions (Pollutant identification on front page)

A.

1. Basis for Allowable Emissions Code:

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units:

4. Equivalent Allowable Emissions: lbs/hr tons/yr

5. Method of Compliance:

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):

B.

1. Basis for Allowable Emissions Code:

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units:

4. Equivalent Allowable Emissions: lbs/hr tons/yr

5. Method of Compliance:

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):

Emissions Unit Information Section 3 of 4

E. POLLUTANT INFORMATION

For the emissions unit addressed in this Emissions Unit Information Section, a separate set of pollutant information must be completed for each pollutant required to be reported. See instructions for further details on this subsection of the Application for Air Permit.

Pollutant Potential/Estimated Emissions: Pollutant 8 of 18

1. Pollutant Emitted: H123

2. Total Percent Efficiency of Control: %

3. Primary Control Device Code:

4. Secondary Control Device Code:

5. Potential Emissions: 0.65 lbs/hr 2.85 tons/yr

6. Synthetically Limited? [x] Yes [ ] No

7. Range of Estimated Fugitive/Other Emissions:

[ ] 1 [ ] 2 [ ] 3 ________ to ________ tons/yr

8. Emission Factor: 0.00086 lb/MMBtu

Reference: See Part B

9. Emissions Method Code (check one):

[ ] 1 [ ] 2 [ ] 3 [ ] 4 [x] 5

10. Calculation of Emissions:

0.00086 lb/MMBtu x 760 MMBtu/hr = 0.65 lb/hr

11. Pollutant Potential/Estimated Emissions Comment:

3.53 TPY total for both boilers

Emissions Unit Information Section 3 **of** 4

Allowable Emissions (Pollutant identification on front page)

A.

1. Basis for Allowable Emissions Code:

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units:

4. Equivalent Allowable Emissions: lbs/hr tons/yr

5. Method of Compliance:

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):

B.

1. Basis for Allowable Emissions Code:

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units:

4. Equivalent Allowable Emissions: lbs/hr tons/yr

5. Method of Compliance:

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):

E. POLLUTANT INFORMATION

For the emissions unit addressed in this Emissions Unit Information Section, a separate set of pollutant information must be completed for each pollutant required to be reported. See instructions for further details on this subsection of the Application for Air Permit.

Pollutant Potential/Estimated Emissions: Pollutant 9 of 18

1. Pollutant Emitted: **H128**

2. Total Percent Efficiency of Control: %

3. Primary Control Device Code:

4. Secondary Control Device Code:

5. Potential Emissions: **1.14** lbs/hr **4.99** tons/yr

6. Synthetically Limited? [x] Yes [ ] No

7. Range of Estimated Fugitive/Other Emissions:

[ ] 1 [ ] 2 [ ] 3 ____________ to ____________ tons/yr

8. Emission Factor: **0.0015 lb/MMBtu**

Reference: **See Part B**

9. Emissions Method Code (check one):

[ ] 1 [ ] 2 [ ] 3 [ ] 4 [x] 5

10. Calculation of Emissions:

0.0015 lb/MMBtu x 760 MMBtu/hr = 1.14 lb/hr

11. Pollutant Potential/Estimated Emissions Comment:

6.16 TPY total for both boilers

Emissions Unit Information Section 3 **of** 4

Allowable Emissions (Pollutant identification on front page)

A.

1. Basis for Allowable Emissions Code:

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units:

4. Equivalent Allowable Emissions: lbs/hr tons/yr

5. Method of Compliance:

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):

B.

1. Basis for Allowable Emissions Code:

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units:

4. Equivalent Allowable Emissions: lbs/hr tons/yr

5. Method of Compliance:

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):

E. POLLUTANT INFORMATION

For the emissions unit addressed in this Emissions Unit Information Section, a separate set of pollutant information must be completed for each pollutant required to be reported. See instructions for further details on this subsection of the Application for Air Permit.

Pollutant Potential/Estimated Emissions: Pollutant 10 of 18

1. Pollutant Emitted: H132

2. Total Percent Efficiency of Control: %

3. Primary Control Device Code:

4. Secondary Control Device Code:

5. Potential Emissions: 0.45 lbs/hr 1.97 tons/yr

6. Synthetically Limited? [x] Yes [ ] No

7. Range of Estimated Fugitive/Other Emissions:

[ ] 1 [ ] 2 [ ] 3 ________ to ________ tons/yr

8. Emission Factor: 0.00059 lb/MMBtu

Reference: See Part B

9. Emissions Method Code (check one):

[ ] 1 [ ] 2 [ ] 3 [ ] 4 [x] 5

10. Calculation of Emissions:

0.00059 lb/MMBtu x 760 MMBtu/hr = 0.45 lb/hr

11. Pollutant Potential/Estimated Emissions Comment:

2.42 TPY total for both boilers

Emissions Unit Information Section 3 of 4

Allowable Emissions (Pollutant identification on front page)

A.

1. Basis for Allowable Emissions Code:

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units:

4. Equivalent Allowable Emissions: lbs/hr tons/yr

5. Method of Compliance:

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):

B.

1. Basis for Allowable Emissions Code:

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units:

4. Equivalent Allowable Emissions: lbs/hr tons/yr

5. Method of Compliance:

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):

Boiler No.2
TSP

Emissions Unit Information Section 3 of 4

E. POLLUTANT INFORMATION

For the emissions unit addressed in this Emissions Unit Information Section, a separate set of pollutant information must be completed for each pollutant required to be reported. See instructions for further details on this subsection of the Application for Air Permit.

Pollutant Potential/Estimated Emissions: Pollutant 11 of 18

1. Pollutant Emitted: **TSP**

2. Total Percent Efficiency of Control: **98** %

3. Primary Control Device Code: **010**

4. Secondary Control Device Code:

5. Potential Emissions: **22.8** lbs/hr **99.86** tons/yr

6. Synthetically Limited? [x] Yes [ ] No

7. Range of Estimated Fugitive/Other Emissions:

[ ] 1 [ ] 2 [ ] 3 __________ to __________ tons/yr

8. Emission Factor: **0.03 lb/MMBtu**

Reference: **NSPS 40 CFR 60 Subpart Da**

9. Emissions Method Code (check one):

[ ] 1 [ ] 2 [ ] 3 [ ] 4 [x] 5

10. Calculation of Emissions:

0.03 lb/MMBtu x 760 MMBtu/hr = 22.8 lb/hr

11. Pollutant Potential/Estimated Emissions Comment:

123.12 TPY total for both boilers

Emissions Unit Information Section 3 of 4

Allowable Emissions (Pollutant identification on front page)

A.

1. Basis for Allowable Emissions Code:
NSPS

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units:
0.03 lb/MMBtu

4. Equivalent Allowable Emissions: 22.8 lbs/hr 99.86 tons/yr

5. Method of Compliance:
Annual stack test using EPA Method 5

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):
Maximum lb/hr based on biomass firing.

B.

1. Basis for Allowable Emissions Code:

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units:

4. Equivalent Allowable Emissions: lbs/hr tons/yr

5. Method of Compliance:

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):

E. POLLUTANT INFORMATION

For the emissions unit addressed in this Emissions Unit Information Section, a separate set of pollutant information must be completed for each pollutant required to be reported. See instructions for further details on this subsection of the Application for Air Permit.

Pollutant Potential/Estimated Emissions: Pollutant 12 of 18

1. Pollutant Emitted: PM10

2. Total Percent Efficiency of Control: 98 %

3. Primary Control Device Code: 010

4. Secondary Control Device Code:

5. Potential Emissions: 22.8 lbs/hr 99.86 tons/yr

6. Synthetically Limited? [x] Yes [ ] No

7. Range of Estimated Fugitive/Other Emissions:

[ ] 1 [ ] 2 [ ] 3 ________ to ________ tons/yr

8. Emission Factor: 0.03 lb/MMBtu

Reference: NSPS 40 CFR 60 Subpart Da

9. Emissions Method Code (check one):

[ ] 1 [ ] 2 [ ] 3 [ ] 4 [x] 5

10. Calculation of Emissions:

0.03 lb/MMBtu x 760 MMBtu/hr = 22.8 lb/hr

11. Pollutant Potential/Estimated Emissions Comment:

123.12 TPY total for both boilers

Emissions Unit Information Section 3 of 4

Allowable Emissions (Pollutant identification on front page)

A.

1. Basis for Allowable Emissions Code:
   NSPS

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units:
   0.03 lb/MMBtu

4. Equivalent Allowable Emissions: 22.8 lbs/hr 99.86 tons/yr

5. Method of Compliance:

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):
   Maximum lb/hr based on biomass firing

B.

1. Basis for Allowable Emissions Code:

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units:

4. Equivalent Allowable Emissions: lbs/hr tons/yr

5. Method of Compliance:

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):

E. POLLUTANT INFORMATION

For the emissions unit addressed in this Emissions Unit Information Section, a separate set of pollutant information must be completed for each pollutant required to be reported. See instructions for further details on this subsection of the Application for Air Permit.

Pollutant Potential/Estimated Emissions: Pollutant 13 of 18

1. Pollutant Emitted: SO2	
2. Total Percent Efficiency of Control: %	
3. Primary Control Device Code:	
4. Secondary Control Device Code:	
5. Potential Emissions: 636 lbs/hr	338 tons/yr
6. Synthetically Limited? [x] Yes [ ] No	
7. Range of Estimated Fugitive/Other Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/yr	
8. Emission Factor: 1.2 lb/MMBtu Reference: Based on NSPS 40 CFR 60 Subpart Da	
9. Emissions Method Code (check one): [ ] 1 [ ] 2 [ ] 3 [ ] 4 [x] 5	
10. Calculation of Emissions: 1.2 lb/MMBtu x 530 MMBtu/hr = 636.0 lb/hr	
11. Pollutant Potential/Estimated Emissions Comment: 338.0 TPY total for both boilers	

Emissions Unit Information Section 3 of 4

Allowable Emissions (Pollutant identification on front page)

A.

1. Basis for Allowable Emissions Code:
NSPS

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units:
1.2 lb/MMBtu

4. Equivalent Allowable Emissions: 636 lbs/hr 339 tons/yr

5. Method of Compliance:
Limit coal burning to 5.4%; fuel analysis; continous SO2 monitor

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):
Based on coal firing

B.

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: 30 lbs/hr 339 tons/yr

5. Method of Compliance:
Limit fuel oil burning to 25%; fuel analysis; continous SO2 monitor

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):
Based on No.2 fuel oil firing and BACT

Emissions Unit Information Section 3 of 4

Allowable Emissions (Pollutant identification on front page)

A.

1. Basis for Allowable Emissions Code:
Other

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units:
0.1 lb/MMBtu 24-hr avg; 0.02 lb/MMBtu, annual average

4. Equivalent Allowable Emissions: 76 lbs/hr 332.9 tons/yr

5. Method of Compliance:
Continuous SO2 Monitor

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):
Based on bagasse firing and fuel sulfur content

B.

1. Basis for Allowable Emissions Code:

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units:

4. Equivalent Allowable Emissions: lbs/hr tons/yr

5. Method of Compliance:

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):

E. POLLUTANT INFORMATION

For the emissions unit addressed in this Emissions Unit Information Section, a separate set of pollutant information must be completed for each pollutant required to be reported. See instructions for further details on this subsection of the Application for Air Permit.

Pollutant Potential/Estimated Emissions: Pollutant 14 of 18

1. Pollutant Emitted: NOx

2. Total Percent Efficiency of Control: 40 %

3. Primary Control Device Code: 081

4. Secondary Control Device Code:

5. Potential Emissions: 88.2 lbs/hr 386.3 tons/yr

6. Synthetically Limited? [x] Yes [ ] No

7. Range of Estimated Fugitive/Other Emissions:

[ ] 1 [ ] 2 [ ] 3 ____________ to ____________ tons/yr

8. Emission Factor: 0.116 lb/MMBtu

Reference: Based on NOx control system

9. Emissions Method Code (check one):

[ ] 1 [x] 2 [ ] 3 [ ] 4 [ ] 5

10. Calculation of Emissions:

0.116 lb/MMBtu x 760 MMBtu/hr = 88.2 lb/hr

11. Pollutant Potential/Estimated Emissions Comment:

477.1 TPY total for both boilers

Emissions Unit Information Section 3 of 4

Allowable Emissions (Pollutant identification on front page)

A.

1. Basis for Allowable Emissions Code:
ESCPSD

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units:
0.116 lb/MMBtu

4. Equivalent Allowable Emissions: 88.2 lbs/hr 386.3 tons/yr

5. Method of Compliance:
Annual stack test using EPA Method 7 or 7E

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):
Based on biomass firing

B.

1. Basis for Allowable Emissions Code: ESCPSD

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units:
0.12 lb/MMBtu

4. Equivalent Allowable Emissions: 72 lbs/hr 157.7 tons/yr

5. Method of Compliance:
Limit fuel oil burning to 25% for entire facility;50% for any single boiler

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):
Based on No.2 fuel oil firing

Emissions Unit Information Section 3 of 4

Allowable Emissions (Pollutant identification on front page)

A.

1. Basis for Allowable Emissions Code:
   ESCPSD

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units:
   0.15 lb/MMBtu

4. Equivalent Allowable Emissions: 79.5 lbs/hr 37.6 tons/yr

5. Method of Compliance:
   Limit coal burning to 5.4% entire facility; 10.8% for any single boiler

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):
   Based on coal firing

B.

1. Basis for Allowable Emissions Code:

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units:

4. Equivalent Allowable Emissions: lbs/hr tons/yr

5. Method of Compliance:

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):

E. POLLUTANT INFORMATION

For the emissions unit addressed in this Emissions Unit Information Section, a separate set of pollutant information must be completed for each pollutant required to be reported. See instructions for further details on this subsection of the Application for Air Permit.

Pollutant Potential/Estimated Emissions: Pollutant 15 of 18

1. Pollutant Emitted: CO

2. Total Percent Efficiency of Control: %

3. Primary Control Device Code:

4. Secondary Control Device Code:

5. Potential Emissions: 266 lbs/hr 1,165.1 tons/yr

6. Synthetically Limited? [x] Yes [ ] No

7. Range of Estimated Fugitive/Other Emissions:

[ ] 1 [ ] 2 [ ] 3 ________ to ________ tons/yr

8. Emission Factor: 0.35 lb/MMBtu

Reference: Based on boiler design

9. Emissions Method Code (check one):

[ ] 1 [x] 2 [ ] 3 [ ] 4 [ ] 5

10. Calculation of Emissions:

0.35 lb/MMBtu x 760 MMBtu/hr = 266 lb/hr

11. Pollutant Potential/Estimated Emissions Comment:

1,436.4 TPY total for both boilers

Emissions Unit Information Section 3 of 4

Allowable Emissions (Pollutant identification on front page)

A.

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: **266** lbs/hr **1,165.1** tons/yr

5. Method of Compliance:
Continous CO monitor

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):
Based on biomass firing

B.

1. Basis for Allowable Emissions Code: **Other**

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units:
0.2 lb/MMBtu

4. Equivalent Allowable Emissions: **120** lbs/hr **262.8** tons/yr

5. Method of Compliance:
Limit fuel burning to 25% entire facility; 50% for any single boiler

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):
Based on No.2 fuel oil firing

Emissions Unit Information Section 3 of 4

Allowable Emissions (Pollutant identification on front page)

A.

1. Basis for Allowable Emissions Code:
   Other

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units:
   0.2 lb/MMBtu

4. Equivalent Allowable Emissions: 106 lbs/hr 50.1 tons/yr

5. Method of Compliance:
   Limit coal buring to 5.4% entire facility; 10.8% for any single boiler

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):
   Based on coal firing

B.

1. Basis for Allowable Emissions Code:

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units:

4. Equivalent Allowable Emissions: lbs/hr tons/yr

5. Method of Compliance:

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):

E. POLLUTANT INFORMATION

For the emissions unit addressed in this Emissions Unit Information Section, a separate set of pollutant information must be completed for each pollutant required to be reported. See instructions for further details on this subsection of the Application for Air Permit.

Pollutant Potential/Estimated Emissions: Pollutant 16 of 18

1. Pollutant Emitted: VOC

2. Total Percent Efficiency of Control: %

3. Primary Control Device Code:

4. Secondary Control Device Code:

5. Potential Emissions: 45.6 lbs/hr 219.15 tons/yr

6. Synthetically Limited? [x] Yes [ ] No

7. Range of Estimated Fugitive/Other Emissions:

[ ] 1 [ ] 2 [ ] 3 ____________ to ____________ tons/yr

8. Emission Factor: 0.06 lb/MMBtu

Reference: Based on boiler design

9. Emissions Method Code (check one):

[ ] 1 [x] 2 [ ] 3 [ ] 4 [ ] 5

10. Calculation of Emissions:

0.06 lb/MMBtu x 760 MMBtu/hr = 45.6 lb/hr

11. Pollutant Potential/Estimated Emissions Comment:

Based on biomass firing

Emissions Unit Information Section 3 of 4
Allowable Emissions (Pollutant identification on front page)

A.

1. Basis for Allowable Emissions Code:
ESCNAA

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units: **0.04 lb/MMBtu Wood Waste**
0.06 lb/MMBtu bagasse

4. Equivalent Allowable Emissions: **45.6** lbs/hr **219.15** tons/yr

5. Method of Compliance:
Annual stack test using EPA Method 25 or 25A

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):
Based on biomass firing, 67% bagasse heat input & 33% wood waste heat input

B.

1. Basis for Allowable Emissions Code: **ESCNAA**

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units:
0.03 lb/MMBtu

4. Equivalent Allowable Emissions: **18** lbs/hr **39.4** tons/yr

5. Method of Compliance:
Limit fuel burning to 25% entire facility; 50% for any single boiler

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):
Based on No.2 fuel oil firing

Emissions Unit Information Section 3 of 4

Allowable Emissions (Pollutant identification on front page)

A.

1. Basis for Allowable Emissions Code:
   ESCNAA

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units:
   0.03 lb/MMBtu

4. Equivalent Allowable Emissions: 15.9 lbs/hr 7.52 tons/yr

5. Method of Compliance:
   Limit coal burning to 5.4% entire facility; 10.8% for any single boiler

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):
   Based on coal firing

B.

1. Basis for Allowable Emissions Code:

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units:

4. Equivalent Allowable Emissions: lbs/hr tons/yr

5. Method of Compliance:

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):

E. POLLUTANT INFORMATION

For the emissions unit addressed in this Emissions Unit Information Section, a separate set of pollutant information must be completed for each pollutant required to be reported. See instructions for further details on this subsection of the Application for Air Permit.

Pollutant Potential/Estimated Emissions: Pollutant 17 of 18

1. Pollutant Emitted: FL

2. Total Percent Efficiency of Control: %

3. Primary Control Device Code:

4. Secondary Control Device Code:

5. Potential Emissions: 12.7 lbs/hr 5.25 tons/yr

6. Synthetically Limited? [x] Yes [ ] No

7. Range of Estimated Fugitive/Other Emissions:

[ ] 1 [ ] 2 [ ] 3 ____________ to ____________ tons/yr

8. Emission Factor: 0.024 lb/MMBtu

Reference: See Part B

9. Emissions Method Code (check one):

[ ] 1 [x] 2 [ ] 3 [ ] 4 [ ] 5

10. Calculation of Emissions:

0.24 lb/MMBtu x 530 MMBtu/hr = 12.7 lb/hr

11. Pollutant Potential/Estimated Emissions Comment:

Based on coal firing

Emissions Unit Information Section 3 of 4

Allowable Emissions (Pollutant identification on front page)

A.

1. Basis for Allowable Emissions Code:
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:
4. Equivalent Allowable Emissions: lbs/hr tons/yr
5. Method of Compliance:
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):

B.

1. Basis for Allowable Emissions Code:
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:
4. Equivalent Allowable Emissions: lbs/hr tons/yr
5. Method of Compliance:
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):

E. POLLUTANT INFORMATION

For the emissions unit addressed in this Emissions Unit Information Section, a separate set of pollutant information must be completed for each pollutant required to be reported. See instructions for further details on this subsection of the Application for Air Permit.

Pollutant Potential/Estimated Emissions: Pollutant 18 of 18

1. Pollutant Emitted: SAM

2. Total Percent Efficiency of Control: %

3. Primary Control Device Code:

4. Secondary Control Device Code:

5. Potential Emissions: 5.3 lbs/hr 6 tons/yr

6. Synthetically Limited? [x] Yes [ ] No

7. Range of Estimated Fugitive/Other Emissions:

[ ] 1 [ ] 2 [ ] 3 ________ to ________ tons/yr

8. Emission Factor: 0.01 lb/MMBtu

Reference: See Part B

9. Emissions Method Code (check one):

[ ] 1 [ ] 2 [x] 3 [ ] 4 [ ] 5

10. Calculation of Emissions:

0.010 lb/MMBtu x 530 MMBtu/hr = 5.3 lb/hr

11. Pollutant Potential/Estimated Emissions Comment:

Based on coal firing

Emissions Unit Information Section 3 **of** 4

Allowable Emissions (Pollutant identification on front page)

A.

1. Basis for Allowable Emissions Code:

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units:

4. Equivalent Allowable Emissions: lbs/hr tons/yr

5. Method of Compliance:

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):

B.

1. Basis for Allowable Emissions Code:

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units:

4. Equivalent Allowable Emissions: lbs/hr tons/yr

5. Method of Compliance:

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):

F. VISIBLE EMISSIONS INFORMATION

This subsection of the Application for Air Permit form must be completed for only those emissions units which are subject to a visible emissions limitation. The intent of this subsection of the form is to identify each activity associated with the emissions unit addressed in this section for which a separate opacity limitation would be applicable. Visible emission subtype codes for each such activity are listed in the instructions for Field 1. Most emissions units will be subject to a "subtype VE" limit only.

Visible Emissions Limitations: Visible Emissions Limitation 1 of 1

1.	Visible Emissions Subtype: VE
2.	Basis for Allowable Opacity: [x] Rule [ ] Other
3.	Requested Allowable Opacity Normal Conditions: 20 % Exceptional Conditions: 27 % Maximum Period of Excess Opacity Allowed: 6 min/hour
4.	Method of Compliance: EPA Method 9
5.	Visible Emissions Comment:

Visible Emissions Limitations: 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:

Visible Emissions Limitations: 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:

G. CONTINUOUS MONITOR INFORMATION

This subsection of the Application for Air Permit form must be completed for only those emissions units which are required by rule or permit to install and operate one or more continuous emission, opacity, flow, or other type monitors. A separate set of continuous monitor information (fields 1-6) must be completed for each monitoring system required.

Continuous Monitoring System Continuous Monitor 1 of 5

1. Parameter Code: **Opacity**

2. CMS Requirement: [x] Rule [ ] Other

3. Monitor Information:

   Monitor Manufacturer:
   Model Number: Serial Number:

4. Installation Date (DD-MON-YYYY):

5. Performance Specification Test Date (DD-MON-YYYY):

6. Continuous Monitor Comment:
   40 CFR 60, Subpart Da

Continuous Monitoring System Continuous Monitor 2 of 5

1. Parameter Code: NOx

2. CMS Requirement: [x] Rule [ ] Other

3. Monitor Information:

   Monitor Manufacturer:
   Model Number: Serial Number:

4. Installation Date (DD-MON-YYYY):

5. Performance Specification Test Date (DD-MON-YYYY):

6. Continuous Monitor Comment:

   40 CFR 60, Subpart Da

Continuous Monitoring System Continuous Monitor 3 of 5

1. Parameter Code: SO2

2. CMS Requirement: [ ] Rule [x] Other

3. Monitor Information:

   Monitor Manufacturer:
   Model Number: Serial Number:

4. Installation Date (DD-MON-YYYY):

5. Performance Specification Test Date (DD-MON-YYYY):

6. Continuous Monitor Comment:

   40 CFR 60, Subpart Da

G. CONTINUOUS MONITOR INFORMATION

This subsection of the Application for Air Permit form must be completed for only those emissions units which are required by rule or permit to install and operate one or more continuous emission, opacity, flow, or other type monitors. A separate set of continuous monitor information (fields 1-6) must be completed for each monitoring system required.

Continuous Monitoring System Continuous Monitor 4 of 5

1. Parameter Code: CO

2. CMS Requirement: [ ] Rule [x] Other

3. Monitor Information:

   Monitor Manufacturer:
   Model Number: Serial Number:

4. Installation Date (DD-MON-YYYY):

5. Performance Specification Test Date (DD-MON-YYYY):

6. Continuous Monitor Comment:
   40 CFR 60, Subpart Da

Continuous Monitoring System Continuous Monitor 5 of 5

1. Parameter Code: O2

2. CMS Requirement: [ ] Rule [x] Other

3. Monitor Information:

   Monitor Manufacturer:
   Model Number: Serial Number:

4. Installation Date (DD-MON-YYYY):

5. Performance Specification Test Date (DD-MON-YYYY):

6. Continuous Monitor Comment:

   40 CFR 60, Subpart Da

Continuous Monitoring System Continuous Monitor ____ of 5

1. Parameter Code:

2. CMS Requirement: [ ] Rule [ ] Other

3. Monitor Information:

   Monitor Manufacturer:
   Model Number: Serial Number:

4. Installation Date (DD-MON-YYYY):

5. Performance Specification Test Date (DD-MON-YYYY):

6. Continuous Monitor Comment:

H. PREVENTION OF SIGNIFICANT DETERIORATION (PSD) INCREMENT TRACKING INFORMATION

This subsection of the Application for Air Permit form must be completed for all applications, not just those undergoing prevention-of-significant-deterioration (PSD) review persuant to Rule 62-212.400, F.A.C. The intent of this subsection is to make a preliminary determination as to whether the emissions unit addressed in this Emissons Unit Information Section consumes PSD increment. PSD increment is consumed (or expanded) as a result of emission increases (decreases) occurring after pollutant-specific baseline dates. Pollutants for which baseline dates have been established are sulfur dioxide, particulate matter, and nitrogen dioxide.

PSD Increment Consumption Determination

1. Increment Consuming for Particulate Matter or Sulfur Dioxide?

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

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

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

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

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

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

2. Increment Consuming for Nitrogen Dioxide?

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

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

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

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

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

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

3.	Increment Consuming/Expanding Code:			
	PM	☒ C	☐ E	☐ Unknown
	SO_2	☒ C	☐ E	☐ Unknown
	NO_2	☒ C	☐ E	☐ Unknown
4.	Baseline Emissions:			
	PM	lbs/hr		tons/yr
	SO_2	lbs/hr		tons/yr
	NO_2			tons/yr
5.	PSD Comment:			

I. EMISSIONS UNIT SUPPLEMENTAL INFORMATION

This subsection of the Application for Air Permit form provides supplemental information related to the emissions unit addressed in this Emissions Unit Information Section. Supplemental information must be submitted as an attachment to each copy of the form, in hard-copy or computer-readable form.

Supplemental Requirements for All Applications

1. Process Flow Diagram

[x] Attached, Document ID: PART B
[ ] Not Applicable [ ] Waiver Requested

2. Fuel Analysis or Specification

[x] Attached, Document ID: PART B
[ ] Not Applicable [ ] Waiver Requested

3. Detailed Description of Control Equipment

[x] Attached, Document ID: PART B
[ ] 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: ____________ [x] Not Applicable
[ ] Previously Submitted, Date: ____________

6. Procedures for Startup and Shutdown

[ ] Attached, Document ID: ____________ [x] Not Applicable

7. Operation and Maintenance Plan

[ ] Attached, Document ID: ____________ [x] Not Applicable

8. Supplemental Information for Construction Permit Application

[x] Attached, Document ID: PART B [ ] Not Applicable

9. Other Information Required by Rule or Statute

[x] Attached, Document ID: PART B [ ] Not Applicable

Additional Supplemental Requirements for Category I Applications Only

10. Alternative Methods of Operation

[ ] Attached, Document ID: ____________ [ ] Not Applicable

11. Alternative Modes of Operation (Emissions Trading)

[ ] Attached, Document ID: ____________ [ ] Not Applicable

12. Enhanced Monitoring Plan

[ ] Attached, Document ID: ____________ [ ] Not Applicable

13. Identification of Additional Applicable Requirements

[ ] Attached, Document ID: ____________ [ ] Not Applicable

14. Acid Rain Permit Application

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

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

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

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

[ ] Not Applicable

EMISSIONS
UNIT 4

Emissions Unit Information Section 4 **of** 4

III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through I 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

This subsection of the Application for Air Permit form provides general information on the emissions unit addressed in this Emissions Unit Information Section, including information on the type, control equipment, operating capacity, and operating schedule of the emissions unit..

Type of Emissions Unit Addressed in This Section

Check one:

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

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, an individually-regulated emission point (stack or vent) serving a single process or production unit, or activity, which also has other individually-regulated emission points.

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

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

Emissions Unit Description and Status

1. Description of Emissions Unit Addressed in This Section:

Fugitive emissions from biomass/coal/ash handling

2. ARMS Identification Number: [x] No Corresponding ID [ ] Unknown

3. Emissions Unit Status Code: C	4. Acid Rain Unit? [ ] Yes [x] No	5. Emissions Unit Major Group SIC Code: 49

6. Initial Startup Date (DD-MON-YYYY):

7. Long-term Reserve Shutdown Date (DD-MON-YYYY):

8. Package Unit:
Manufacturer: Model Number:

9. Generator Nameplate Rating: MW

10. Incinerator Information:

Dwell Temperature: °F
Dwell Time: seconds
Incinerator Afterburner Temperature: °F

11. Emissions Unit Comment:

Emissions Unit Control Equipment Information

A.

1. Description:

Baghouse

2. Control Device or Method Code: **018**

B.

1. Description:

Enclosures

2. Control Device or Method Code: **054**

C.

1. Description:

2. Control Device or Method Code:

Emissions Unit Operating Capacity

1. Maximum Heat Input Rate:
mmBtu/hr

2. Maximum Incineration Rate:
lbs/hr tons/day

3. Maximum Process or Throughput Rate:
956,647 TPY

4. Maximum Production Rate:

5. Operating Capacity Comment:
956,647 TPY biomass; 18,221 TPY coal

Emissions Unit Operating Schedule

1. Requested Maximum Operating Schedule:

24 hours/day, 7 days/week,

52 weeks/yr 8760 hours/yr

B. EMISSIONS UNIT REGULATIONS

Depending on the application category, this subsection of the Application for Air Permit form provides either a brief analysis or detailed listing of all federal, state, and local regulations applicable to the emissions unit addressed in this Emissions Unit Information Section.

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

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

62-296.300(2)
62-296.300(3)

C. EMISSION POINT (STACK/VENT) INFORMATION

This subsection of the application for Air Permit form provides information about the emission point associated with the emissions unit addressed in this Emissions Unit Information Section. An emission point is typically a stack or vent but can be any identifiable location at which air pollutants, including fugitive emissions, are discharged into the atmosphere.

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram:

   Fuel Handling System

2. Emission Point Type Code:

   [ ] 1 [ ] 2 [ ] 3 [x] 4

3. Descriptions of Emissions Points Comprising this Emissions Unit:

4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:

5. Discharge Type Code:

   [ ] D [x] F [ ] H [ ] P
   [ ] R [ ] V [ ] W

6. Stack Height:	ft
7. Exit Diameter:	ft
8. Exit Temperature:	77 °F
9. Actual Volumetric Flow Rate:	acfm
10. Percent Water Vapor:	%
11. Maximum Dry Standard Flow Rate:	dscfm
12. Nonstack Emission Point Height:	10 ft

13. Emission Point UTM Coordinates:

Zone: 17 East (km): 544.2 North (km): 2968

14. Emission Point Comment:

Fugitive emissions

D. SEGMENT (PROCESS/FUEL) INFORMATION

For the emissions unit addressed in this Emissions Unit Information Section, a separate set of segment data (Fields 1-10) must be completed for each segment required to be reported and for each alternative operating method or mode (emissions trading scenario) under Chapter 62-213, F.A.C., for which the maximum hourly or annual segment-related rate would vary. A segment is a material handling, process, fuel burning, volatile organic liquid storage, production, or other such operation to which emissions of the unit are directly related. See instructions for further details on this subsection of the Application for Air Permit.

Segment Description and Rate Information: Segment 1 of 2

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode):
   Biomass

2. Source Classification Code (SCC):

3. SCC Units:
   tons

4. Maximum Hourly Rate:

5. Maximum Annual Rate:

6. Estimated Annual Activity Factor:
   956,647

7. Maximum Percent Sulfur:

8. Maximum Percent Ash:

9. Million Btu per SCC Unit:

10. Segment Comment:

Segment Description and Rate Information: Segment 2 of 2

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode):
   Bituminous coal handling

2. Source Classification Code (SCC):

3. SCC Units: **tons**

4. Maximum Hourly Rate:

5. Maximum Annual Rate: **18,221**

6. Estimated Annual Activity Factor: **18,221**

7. Maximum Percent Sulfur:

8. Maximum Percent Ash:

9. Million Btu per SCC Unit:

10. Segment Comment:

E. POLLUTANT INFORMATION

For the emissions unit addressed in this Emissions Unit Information Section, a separate set of pollutant information must be completed for each pollutant required to be reported. See instructions for further details on this subsection of the Application for Air Permit.

Pollutant Potential/Estimated Emissions: Pollutant 1 of 2

1. Pollutant Emitted: **PM (TSP)**

2. Total Percent Efficiency of Control: %

3. Primary Control Device Code:

4. Secondary Control Device Code:

5. Potential Emissions: lbs/hr **21.1** tons/yr

6. Synthetically Limited? [ ] Yes [x] No

7. Range of Estimated Fugitive/Other Emissions:

[ ] 1 [ ] 2 [ ] 3 ___________ to ___________ tons/yr

8. Emission Factor:

Reference: **See Part B, Table 2-13**

9. Emissions Method Code (check one):

[ ] 1 [ ] 2 [x] 3 [ ] 4 [ ] 5

10. Calculation of Emissions:

See Part B, Table 2-13

11. Pollutant Potential/Estimated Emissions Comment:

Fugitive emissions associated with fuel/ash handling

Emissions Unit Information Section 4 of 4

Allowable Emissions (Pollutant identification on front page)

A.

1. Basis for Allowable Emissions Code:

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units:

4. Equivalent Allowable Emissions: lbs/hr tons/yr

5. Method of Compliance:

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):

B.

1. Basis for Allowable Emissions Code:

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units:

4. Equivalent Allowable Emissions: lbs/hr tons/yr

5. Method of Compliance:

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):

Emissions Unit Information Section 4 of 4

E. POLLUTANT INFORMATION

For the emissions unit addressed in this Emissions Unit Information Section, a separate set of pollutant information must be completed for each pollutant required to be reported. See instructions for further details on this subsection of the Application for Air Permit.

Pollutant Potential/Estimated Emissions: Pollutant 2 of 2

1. Pollutant Emitted: PM10	
2. Total Percent Efficiency of Control: %	
3. Primary Control Device Code:	
4. Secondary Control Device Code:	
5. Potential Emissions: lbs/hr	15.86 tons/yr
6. Synthetically Limited? [ ] Yes [x] No	
7. Range of Estimated Fugitive/Other Emissions: [ ] 1 [ ] 2 [ ] 3 ________ to ________ tons/yr	
8. Emission Factor: Reference: See Part B, Table 2-13	
9. Emissions Method Code (check one): [ ] 1 [ ] 2 [x] 3 [ ] 4 [ ] 5	
10. Calculation of Emissions: See Part B, Table 2-13	
11. Pollutant Potential/Estimated Emissions Comment: Fugitive emissions associated with fuel/ash handling	

Emissions Unit Information Section 4 **of** 4

Allowable Emissions (Pollutant identification on front page)

A.

1. Basis for Allowable Emissions Code:		
2. Future Effective Date of Allowable Emissions:		
3. Requested Allowable Emissions and Units:		
4. Equivalent Allowable Emissions:	lbs/hr	tons/yr
5. Method of Compliance:		
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):		

B.

1. Basis for Allowable Emissions Code:		
2. Future Effective Date of Allowable Emissions:		
3. Requested Allowable Emissions and Units:		
4. Equivalent Allowable Emissions:	lbs/hr	tons/yr
5. Method of Compliance:		
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode):		

F. VISIBLE EMISSIONS INFORMATION

This subsection of the Application for Air Permit form must be completed for only those emissions units which are subject to a visible emissions limitation. The intent of this subsection of the form is to identify each activity associated with the emissions unit addressed in this section for which a separate opacity limitation would be applicable. Visible emission subtype codes for each such activity are listed in the instructions for Field 1. Most emissions units will be subject to a "subtype VE" limit only.

Visible Emissions Limitations: Visible Emissions Limitation 1 of 1

1. Visible Emissions Subtype: VE

2. Basis for Allowable Opacity: [x] Rule [ ] Other

3. Requested Allowable Opacity
Normal Conditions: 20 % Exceptional Conditions: %
Maximum Period of Excess Opacity Allowed: min/hour

4. Method of Compliance:
VE test using Method 9

5. Visible Emissions Comment:
62-296.300(3)

Visible Emissions Limitations: Visible Emissions Limitation _____ of 1

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:

Visible Emissions Limitations: Visible Emissions Limitation _____ of 1

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:

G. CONTINUOUS MONITOR INFORMATION

This subsection of the Application for Air Permit form must be completed for only those emissions units which are required by rule or permit to install and operate one or more continuous emission, opacity, flow, or other type monitors. A separate set of continuous monitor information (fields 1-6) must be completed for each monitoring system required.

Continuous Monitoring System Continuous Monitor _____ of _____

1.	Parameter Code:
2.	CMS Requirement: [ ] Rule [ ] Other
3.	Monitor Information: Monitor Manufacturer: Model Number: Serial Number:
4.	Installation Date (DD-MON-YYYY):
5.	Performance Specification Test Date (DD-MON-YYYY):
6.	Continuous Monitor Comment:

Continuous Monitoring System Continuous Monitor _____ of _____

1. Parameter Code:

2. CMS Requirement: [ ] Rule [ ] Other

3. Monitor Information:

   Monitor Manufacturer:
   Model Number: Serial Number:

4. Installation Date (DD-MON-YYYY):

5. Performance Specification Test Date (DD-MON-YYYY):

6. Continuous Monitor Comment:

Continuous Monitoring System Continuous Monitor _____ of _____

1. Parameter Code:

2. CMS Requirement: [ ] Rule [ ] Other

3. Monitor Information:

   Monitor Manufacturer:
   Model Number: Serial Number:

4. Installation Date (DD-MON-YYYY):

5. Performance Specification Test Date (DD-MON-YYYY):

6. Continuous Monitor Comment:

H. PREVENTION OF SIGNIFICANT DETERIORATION (PSD) INCREMENT TRACKING INFORMATION

This subsection of the Application for Air Permit form must be completed for all applications, not just those undergoing prevention-of-significant-deterioration (PSD) review persuant to Rule 62-212.400, F.A.C. The intent of this subsection is to make a preliminary determination as to whether the emissions unit addressed in this Emissons Unit Information Section consumes PSD increment. PSD increment is consumed (or expanded) as a result of emission increases (decreases) occurring after pollutant-specific baseline dates. Pollutants for which baseline dates have been established are sulfur dioxide, particulate matter, and nitrogen dioxide.

PSD Increment Consumption Determination

1. Increment Consuming for Particulate Matter or Sulfur Dioxide?

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

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

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

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

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

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

2. Increment Consuming for Nitrogen Dioxide?

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

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

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

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

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

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

3.	Increment Consuming/Expanding Code:			
	PM	[ ] C	[ ] E	[ ] Unknown
	SO_2	[ ] C	[ ] E	[ ] Unknown
	NO_2	[ ] C	[ ] E	[ ] Unknown
4.	Baseline Emissions:			
	PM	lbs/hr		tons/yr
	SO_2	lbs/hr		tons/yr
	NO_2			tons/yr
5.	PSD Comment:			

I. EMISSIONS UNIT SUPPLEMENTAL INFORMATION

This subsection of the Application for Air Permit form provides supplemental information related to the emissions unit addressed in this Emissions Unit Information Section. Supplemental information must be submitted as an attachment to each copy of the form, in hard-copy or computer-readable form.

Supplemental Requirements for All Applications

1. Process Flow Diagram

[X] Attached, Document ID: PART B
[ ] Not Applicable [ ] Waiver Requested

2. Fuel Analysis or Specification

[ ] Attached, Document ID: ________
[X] Not Applicable [ ] Waiver Requested

3. Detailed Description of Control Equipment

[X] Attached, Document ID: PART B
[ ] Not Applicable [ ] Waiver Requested

4. Description of Stack Sampling Facilities

[ ] Attached, Document ID: ________
[ ] Not Applicable [X] Waiver Requested

5. Compliance Test Report

[ ] Attached, Document ID: ________ [X] Not Applicable
[ ] Previously Submitted, Date: ________

6. Procedures for Startup and Shutdown

[ ] Attached, Document ID: ________ [X] Not Applicable

7. Operation and Maintenance Plan

[ ] Attached, Document ID: ________ [X] Not Applicable

8. Supplemental Information for Construction Permit Application

[X] Attached, Document ID: PART B [ ] Not Applicable

9. Other Information Required by Rule or Statute

[X] Attached, Document ID: PART B [ ] Not Applicable

Additional Supplemental Requirements for Category I Applications Only

10. Alternative Methods of Operation

☐ Attached, Document ID: ____________ ☐ Not Applicable

11. Alternative Modes of Operation (Emissions Trading)

☐ Attached, Document ID: ____________ ☐ Not Applicable

12. Enhanced Monitoring Plan

☐ Attached, Document ID: ____________ ☐ Not Applicable

13. Identification of Additional Applicable Requirements

☐ Attached, Document ID: ____________ ☐ Not Applicable

14. Acid Rain Permit Application

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

☐ Repowering Extension Plan (Form No. 62-210.900(1)(a)1.)
Attached, Document ID: ____________

☐ New Unit Exemption (Form No. 62-210.900(1)(a)2.)
Attached, Document ID: ____________

☐ Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)
Attached, Document ID: ____________

☐ Not Applicable

PART B

SUPPLEMENTAL INFORMATION FOR PERMIT APPLICATION

1.0 INTRODUCTION

Osceola Power Limited Partnership (Osceola Power) was issued a prevention of significant deterioration (PSD) permit in 1993 and an amendment in 1994 for construction of a 65 megawatt electric (MWe) cogeneration facility. The cogeneration facility, which is currently under construction, will use primarily biomass (bagasse and wood waste materials) to generate steam and electricity. The cogeneration facility will be located at the site of the existing Osceola Farms sugar mill located east of Pahokee, Florida. The existing sugar mill boilers will be replaced with a cogeneration system consisting of two new combustion units and a steam turbine electric generator.

The cogeneration facility will provide enough steam energy for the needs of the Osceola Farms sugar mill and will generate electricity which will be sold to Florida Power & Light Company (FPL). Further, the proposed facility will reduce overall air emissions and water consumption compared to the existing facility while generating approximately 18 times more electric energy than the existing facility.

The state construction permit (AC50-219795) and federal PSD permit (PSD-FL-197) were issued to Osceola Power on September 27, 1993. Since that time, final engineering has been progressing, and as a result certain design and operating parameters have been refined. Based on the current design of the plant, Osceola Power is now requesting certain changes to the current PSD construction permit. The primary changes are in the maximum hourly and annual heat input rates. Most of these changes are minor, and do not represent a significant change from the current permit. The changes do not require PSD or nonattainment new source review.

This report presents a description of the proposed changes, including updated design information, emission rates and air quality impacts. Based on the original PSD baseline emissions presented in the original application for the Osceola facility and future maximum emissions from the proposed cogeneration facility, neither PSD or nonattainment review is indicated as a result of the proposed changes.

This supplemental information report contains three additional sections. A complete description of the project, including air emission rates and stack parameters, is presented in Section 2.0. The air quality requirements for the project and new source review applicability are discussed in Section 3.0. An updated air quality impact (dispersion modeling) analysis is presented in Section 4.0. Supportive information is contained in the appendices.

2.0 PROJECT DESCRIPTION

2.1 CURRENT COGENERATION FACILITY AIR PERMIT

Osceola Power was issued a state construction permit (AC50-219795) and federal PSD permit (PSD-FL-197) on September 27, 1993, for the construction of a 60 MWe (gross) capacity biomass/coal-fired cogeneration facility. The permit was amended on April 8, 1994 to allow up to 65 MWe (gross) generating capacity. Each boiler was expected to produce up to 440,000 lbs/hr steam. During the sugar processing season, the cogeneration facility is to provide steam to the existing Osceola Farms sugar mill by burning primarily bagasse, which is the residual cellulose fiber resulting from the sugar cane grinding process, while also generating electricity. During the off-season, the cogeneration facility will burn primarily wood waste to generate electricity.

The construction permit limited the maximum heat input to each of the two boilers to 665 million British thermal units per hour (MMBtu/hr) when firing biomass, and 460 MMBtu/hr when firing fossil fuels (No. 2 fuel oil or low sulfur coal). Maximum annual heat input to the entire facility was limited to 7.0×10^{12} Btu/yr, and maximum coal burning was limited to 20,065 tons per year (TPY), which is approximately 7 percent of the total annual heat input.

The two new boilers are subject to federal new source performance standards (NSPS) for electric utility boilers (40 CFR 60, Subpart Da). Air pollution control equipment serving the boilers consisted of 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 mercury control system. The stacks serving the boilers were to be a minimum of 180 feet tall.

A regional map showing the location of the site is presented in Figure 2-1. A location map showing the existing sugar mill, cogeneration site, and plant property boundaries is presented in Figure 2-2.

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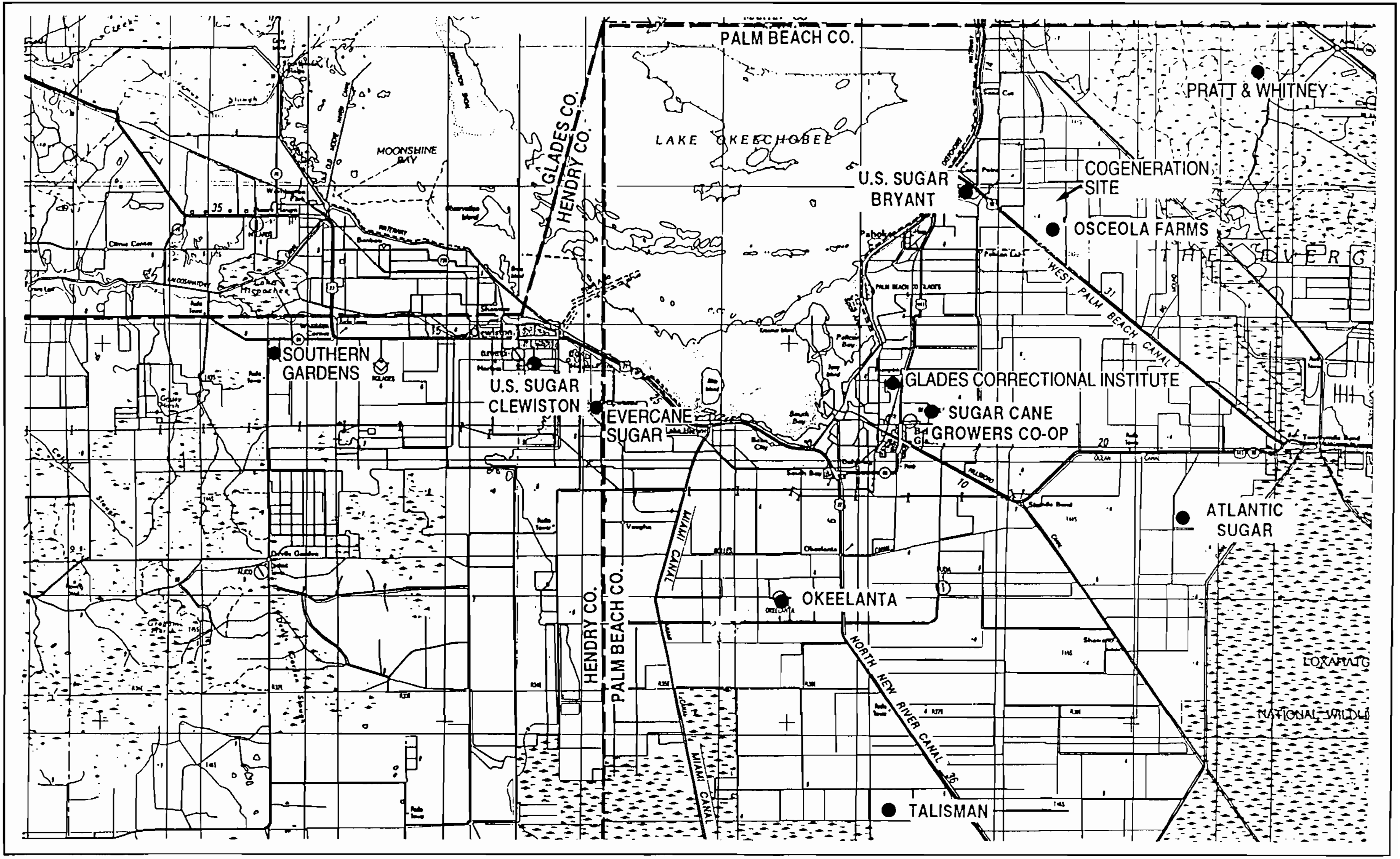

Figure 2-1
Regional Site Map

KBN

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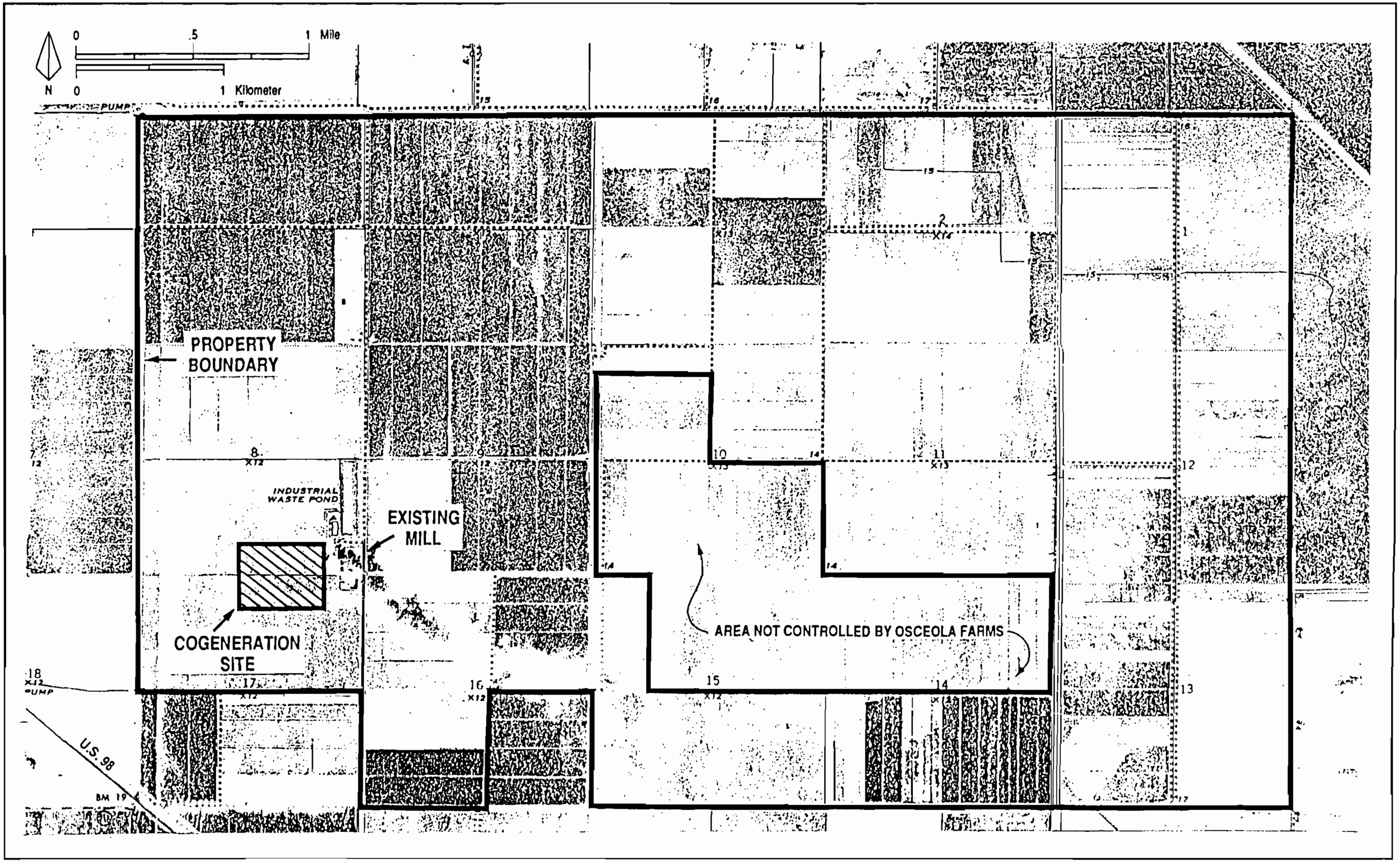

Figure 2-2
Site Location Map

Source: USGS, 1970.

2.2 COGENERATION FACILITY DESIGN INFORMATION

This section presents updated operating information concerning the cogeneration facility. Information presented in the original PSD application is provided, even if such information has not changed since the original submittal, in order to provide complete information.

2.2.1 STEAM TURBINE AND BOILERS

A maximum 74 MWe (gross) cogeneration system is proposed which will be used to provide steam to the Osceola Farms sugar mill, and additionally will deliver a substantial amount of electricity to FPL to supply its customers in south Florida. The original PSD permit was for a 65 MWe (gross) cogeneration system; however, final design has provided enhanced efficiencies in the system, and it is anticipated that the boilers being installed will be able to be operated above their design capacities. This may allow opportunity to operate only one boiler at certain times as opposed to operating both boilers.

The proposed facility will operate with two steam boilers burning biomass (primarily bagasse and wood waste materials). The boilers will be ABB Combustion Engineering Systems Model VU-40 units, as presented in the original application. Design features of the boilers include the following:

- ABB Model VU-40 steam generator
- Two-drum, field erected, open pass, balanced draft steam generators
- Water cooled furnace with electrical resistance welded steel boiler tubes
- Superheater section
- Economizer section
- Primary and overfire air systems
- Primary air preheater
- Overfire air preheater
- Plenum hoppers, boiler hoppers and air heater hoppers for collection of fly ash
- Forced draft and induced draft fans
- Primary and overfire air systems
- Peabody Model DFL-870, No. 2 fuel oil burner; steam atomizing; 150 MMBtu/hr heat input maximum
- Spreader stoker, with continuous front ash discharge, vibrating grate, water cooling, grate area of 624 ft^2

Design data for each boiler are as follows:

Furnace volume = 40,700 ft^3

Steam temperature = 955°F

Steam pressure = 1,755 psig (design); 1,540 psig (operating)

Maximum steam output = 506,000 lb/hr

Maximum heat input = 760 x 10^6 Btu/hr (biomass)

= 600 MMBtu/hr (No.2 fuel oil)

= 530 x 10^6 Btu/hr (coal)

The boilers are balanced draft boilers and will operate under a slight negative pressure (about 0.1 inch H_2O). A balanced draft furnace prevents leakage of flue gas out of the unit. Any air movement through the boiler walls will be in the form of air in-leakage.

The boilers are designed for a pressure of 1,755 psig. The actual operating pressure will be approximately 1,540 psig with a steam temperature of approximately 955°F. Maximum steam production for each boiler will be 506,000 lb/hr. A general arrangement view of the boilers is provided in Appendix B.

The cogeneration facility will be designed to provide the Osceola Farms sugar mill with approximately 300,000 lb/hr of steam at 250 to 350 psig and 550°F, and approximately 300,000 lb/hr of steam at 22 psig and 280°F during the crop season. These steaming rates may vary as a function of operational conditions; equipment and process efficiencies; characteristics of the fuel, which is an agricultural product and somewhat variable; and overall sugar mill production rate. The process steam conditions will normally be controlled within a ±10 percent range. During normal operating conditions, the process steam flow can be expected to fluctuate within a ±25 percent range. During startup, shutdown, upset, or transient conditions, steam flow could diminish to zero.

The facility will produce up to 74 MWe (gross) of electricity year-round. A simplified flow diagram of the process is provided in Figure 2-3.

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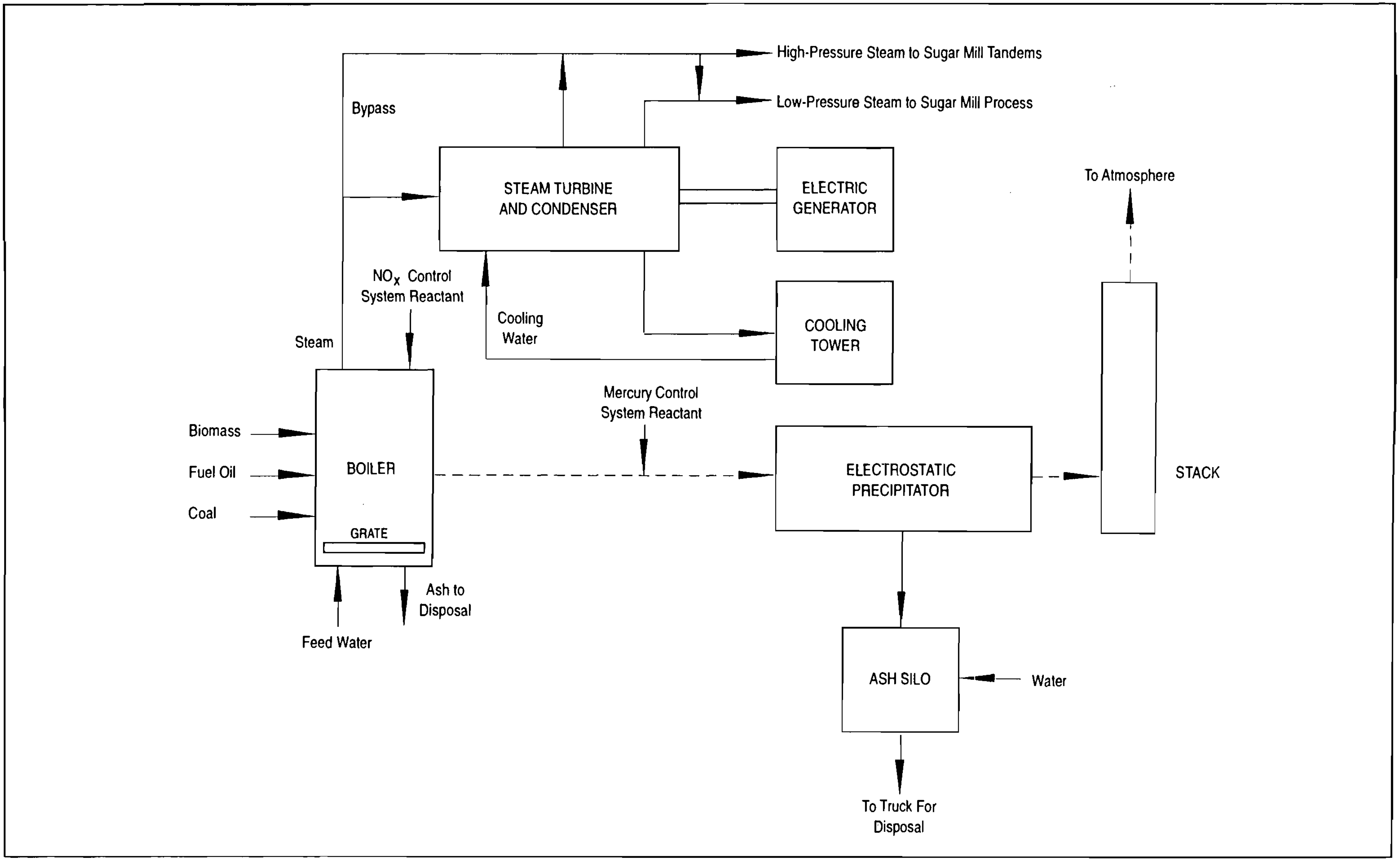

Figure 2-3
Simplified Flow Diagram for Osceola Power Cogeneration Facility

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The cogeneration facility is currently under construction, and first firing in the boilers is expected to take place in October 1995. Commercial operation is expected to occur in June 1996.

During the period from initial firing until commercial operation, the existing Osceola Farms boilers may operate simultaneously with the cogeneration boilers. Only biomass or No. 2 fuel oil will be fired in the cogeneration boilers during this period. In addition, if the cogeneration boilers generate more than 570,000 lbs/hr steam during this period, steam in excess of 570,000 lb/hr will be sent to the Osceola Farms sugar mill, and the existing Osceola Farms sugar mill boilers will reduce steam production by an equivalent amount. This period of simultaneous operation will not exceed 12 months, and simultaneous operation during this period will not occur on more than 120 calendar days.

After the first 12 months of cogeneration facility operation, or after commercial operation begins, whichever occurs first, the existing Osceola Farms sugar mill boilers will be operated only when both cogeneration facility boilers are shutdown. The existing boilers will be permanently disabled and made incapable of operation within three years of commercial startup of the cogeneration facility, but no later than January 1, 1999.

2.2.2 FUELS

Osceola Power is planning on burning 100 percent biomass fuels. It is planned that the bagasse from the sugar grinding operation will provide approximately two-thirds of the annual fuel requirements of the facility. The remaining fuel requirements will be provided by wood waste materials, which could include clean construction and demolition wood debris, yard trimmings, land clearing debris, and other clean cellulose and vegetative matter. However, because wood waste materials are not commodity fuels and the supply of wood waste may fluctuate, it is necessary to have the ability to burn limited amounts of fossil fuel in the event that the supply of biomass fuel is not adequate. Therefore, each combustion unit will have the capability to burn biomass, very low sulfur fuel oil, and coal, either alone or in combination.

The cogeneration facility will use very low sulfur No. 2 fuel oil only to assist in startup or when the biomass fuel supply is not adequate. The No. 2 distillate fuel oil will have a maximum sulfur content of 0.05 percent and an equivalent maximum SO_2 emission rate of 0.05 lb/MMBtu.

Coal will be utilized only when the biomass fuel supply is not adequate. Coal fired in the facility will be low sulfur coal of approximately 0.7 percent sulfur content, with an equivalent maximum SO_2 emission rate of 1.2 lb/MMBtu.

Biomass and coal will be burned on a vibrating grate located within each boiler. In this design, fuel combusts in suspension above the grate or on the grate surface. Both underfire and overfire air are supplied to enhance combustion efficiency. Ash is removed from the grate by periodically vibrating the grate. The boilers will be equipped with fuel oil burners designed to provide maximum combustion efficiency. An associated fuel storage tank and piping will also be installed.

Fuel specifications for each fuel that may be utilized by the cogeneration facility are presented in Table 2-1. Based on these fuel specifications, maximum hourly firing rates are shown in Table 2-2 for each fuel when fired alone. The maximum heat input to each boiler due to biomass fuels will be 760 MMBtu/hr. Due to limitations of the fuel oil firing system, maximum heat input of No. 2 fuel oil will be limited to 600 MMBtu/hr. Maximum heat input due to coal will be 530 MMBtu/hr. Biomass and fossil fuels may also be burned in combination, not to exceed a total heat input of 760 MMBtu/hr per boiler.

On an annual basis, all fuels may be fired alone or in combination, not to exceed a total heat input for both boilers of 8.208×10^{12} Btu/yr. In addition, burning of No. 2 fuel oil will be limited to a total of 25 percent of the total annual heat input and coal burning will be limited to 5.4 percent annually. Three cases are shown in Table 2-2 to illustrate the anticipated scenario of firing 100 percent biomass fuel and the potential cases of firing the maximum amount of fuel oil or the maximum amount of coal, with the remaining heat input due to biomass. When only biomass is fired, the annual heat input requirement is 8.208×10^{12} Btu/yr for the entire facility (total both boilers). Under the worst-case fuel oil burning case of firing No. 2 fuel oil at 25 percent of the total annual heat input, the annual heat input requirement for the entire facility becomes 7.724×10^{12} Btu/yr, due to the different heat transfer efficiency for No. 2 fuel oil versus biomass. Similarly, under the worst-case coal firing case of firing coal at 5.4 percent of the total annual heat input, the annual heat input requirement for the entire facility becomes 8.098×10^{12} Btu/yr.

Table 2-1. Design Fuel Specifications[a] for the Osceola Power Cogeneration Facility

Parameter	Biomass Bagasse	Biomass Wood Waste	No. 2 Fuel Oil	Bituminous Coal
Specific Gravity	--	--	0.865	--
Heating Value (Btu/lb)	4,250	5,500	19,175	12,000
Heating Value (Btu/gal)	--	--	138,000	--
Ultimate Analysis (dry basis):				
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	0.009%	0.009%	0.50%	0.67%
Ash/Inorganic	0.83%	3.24%	0.00%	3.66%
Moisture	52%	37%	--	4.5%

[a] Represents average fuel characteristics.

Sources: Okeelanta Corp., 1992.
Combustion Engineering, 1981.

Table 2-2. Maximum Fuel Usage and Heat Input Rates, Osceola Power Limited Partnership

Fuel	Heat Input	Heat Transfer Efficiency (%)	Heat Output	Fuel Firing Rate	
	Maximum Short-Term (per boiler)				
	(MMBtu/hr)		(MMBtu/hr)		
Biomass	760	68	517	178,824	lb/hr
No. 2 Fuel Oil	600	85	510	4,348	gal/hr
Coal	530	85	451	44,167	lb/hr
	Annual Average (total two boilers)				
	(Btu/yr)		(Btu/yr)		
NORMAL OPERATIONS					
Biomass	8.208E+12	68	5.581E+12	965,647	TPY
No. 2 Fuel Oil	0	85	0	0	gal/yr
Coal	0	85	0	0	TPY
TOTAL	8.208E+12		5.581E+12		
25% OIL FIRING					
Biomass	5.793E+12	68	3.939E+12	681,529	TPY
No. 2 Fuel Oil	1.931E+12	85	1.641E+12	13,992,754	gal/yr
Coal	0	85	0	0	TPY
TOTAL	7.724E+12		5.581E+12		
5.4% COAL FIRING					
Biomass	7.661E+12	68	5.209E+12	901,294	TPY
No. 2 Fuel Oil	0	85	0	0	gal/yr
Coal	4.373E+11	85	3.717E+11	18,221	TPY
TOTAL	8.098E+12		5.581E+12		

Notes: Total heat output required = 5.581E+12 Btu/yr total both boilers.
Fuels may be burned in combination, not to exceed total heat outputs.
Based on fuel heating values as follows:
Bagasse – 4,250 Btu/lb
No. 2 Fuel Oil – 138,000 Btu/gal
Coal – 12,000 Btu/lb

<u>Basis for annual heat input</u>

Grinding season: 440,000 lb/hr/boiler steam; 658 MMBtu/hr/boiler; 140 crop days
Heat input= 4.4218E+12 Btu/yr

Non-grinding season: 273,150 lb/hr/boiler steam; 369 MMBtu/hr/boiler; 225 crop days; 95% capacity
Heat input= 3.7859E+12 Btu/yr

Totals: Heat input= 8.2077E+12 Btu/yr

2.2.3 FUEL HANDLING SYSTEM

The fuel handling system will be initially designed to handle biomass. The fuel systems are designed to feed reduced rates to the boilers to match boiler demand/use rates. Biomass fuel can be delivered to the facility and boilers in several ways. A flow diagram of the biomass fuel handling system is presented in Figure 2-4.

Under normal conditions during the grinding season, bagasse from the sugar mill will be delivered directly to the boilers by a belt conveyor system. Overfeed from the system will be conveyed to the biomass storage pile. Wood waste can be mixed with the bagasse in the biomass storage pile and be utilized during the grinding season as needed. The biomass will be conveyed from the biomass storage pile to the boilers through the biomass handling system. These conveyor belts will be enclosed, and the conveyor transfer points will be partially enclosed.

During the non-grinding season and at other times as necessary, wood waste will be delivered to the facility by truck. The trucks will discharge the material into a dump hopper. The truck dump hopper will be open, but all subsequent conveyor belts will be covered and transfer points will be partially enclosed. From the dump hoppers, the wood waste will be placed on a conveyor belt, pass through a screen and hogger, and then placed on another conveyor to the boiler building or to the biomass storage pile. If directed to the boilers, the material will be transferred from the conveyor belt to the fuel distribution conveyor and then to the boiler feeder bins.

If directed to the biomass storage pile, the biomass will be transferred to the radial stacker, and then discharge onto the storage pile. From the storage pile, the biomass will be moved by mobile equipment to the underpile reclaimer devices. Biomass from the reclaim system will be deposited on a conveyor and delivered to the boilers via the previously described system.

A baghouse dust collector will be located at the boiler building in order to control particulate emissions generated from the distribution conveyors and the transfer hoppers in the boiler house. A schematic of this system is shown in Figure 2-4 and Appendix B. The baghouse will be designed for 30,000 acfm with an air-to-cloth ratio of 6.6:1. The baghouse will be located outside of the boiler building at ground level.

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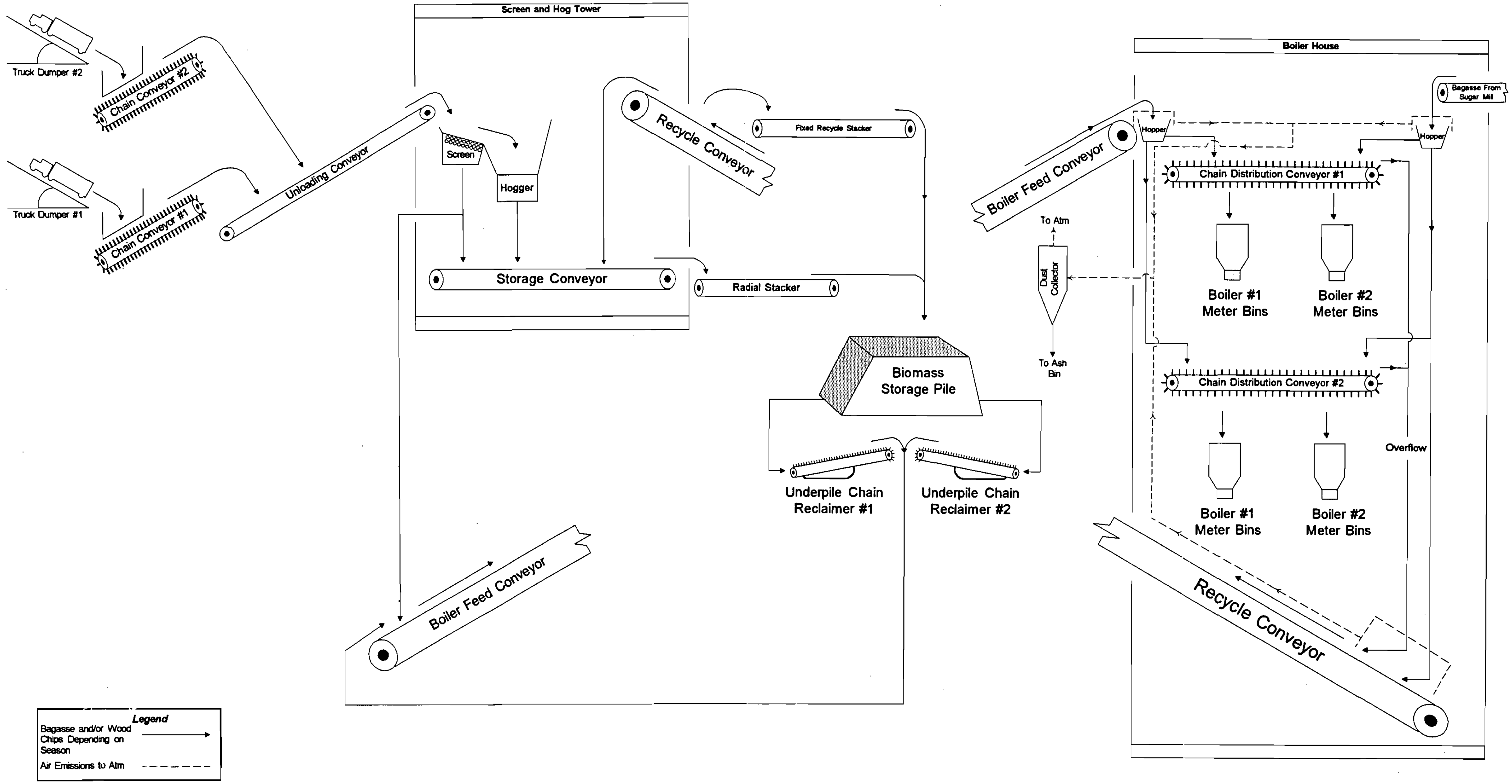

Figure 2-4
Osceola Power Fuel Handling System

Coal handling facilities will be constructed as needed prior to coal-firing. The coal handling system will consist of unloading, transfer, storage, reclaiming, and crushing operations. The railcar unloading system will utilize a bottom dumping type facility or equivalent. Coal will be delivered to the site via trains consisting of up to 75 railcars or by truck. Each railcar may hold up to 100 tons and each truck up to 25 tons. The cogeneration facility may burn up to approximately 18,221 tons of coal per year under the scenario of 5.4 percent of total annual heat input from coal.

2.2.4 ASH HANDLING SYSTEM

Ash generated from the combustion process will consist of bottom ash, siftings ash, and fly ash. Bottom ash is ash which falls off the front of the grate onto a submerged conveyor. Siftings ash is ash which drops down through the grate to the bottom of the boiler. Fly ash is ash captured downstream of the boiler in the boiler bank hoppers, air preheater hoppers, and the ESP.

Bottom ash generated in the boilers will be handled wet via a submerged drag-chain conveyor. This ash will be discharged to a storage pile and then removed by frontend loader. The frontend loader will be used to the load the ash into trucks for offsite disposal. Bottom ash will be handled in a wet state and therefore particulate emissions will be minimal.

The siftings ash collected at the bottom of the boiler will be periodically removed from the boiler by manual means on an as needed basis. This ash will be loaded into trucks by frontend loader for subsequent offsite disposal.

The fly ash collected downstream of the boiler will be conveyed via enclosed drag-chain or screw type conveyors to an ash silo (one silo for the facility). The ash will be conditioned with water prior to loading into trucks for offsite disposal. The silo will have a silo bin vent filter to control particulate matter emissions. A schematic of this system is presented in Appendix B. The design flow rate for the filter is 2,500 acfm, with an air-to-cloth ratio of 4:1.

The bottom ash and fly ash due to biomass firing will be segregated from the coal ash. Whenever coal firing commences, any ash placed in the bottom ash pile or in the fly ash silos from that point on will be treated as coal ash. This will continue until such time as coal firing ceases and coal ash clears the system. Once specific ash handling equipment has been selected, the maximum time for ash to clear the system can be calculated. To provide assurance that coal ash is not mixed with biomass ash, ash will continue to be handled as coal ash during this time plus an additional two hours.

2.2.5 FACILITY PLOT PLAN

A revised plot plan of the Osceloa Power cogeneration facility is presented in Figure 2-5. The major structures at the site are the two boiler buildings. These buildings will have a height of approximately 121 feet above ground.

2.2.6 CONTROL EQUIPMENT INFORMATION

The cogeneration facility will utilize several emission control techniques to reduce emissions. A selective non-catalytic reduction (SNCR) system will be used to reduce NO_x emissions. SNCR is a system which injects urea into the boiler to reduce NO_x emissions. Further, the cogeneration boilers will 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 better controls over the furnace loads and transient conditions. Particulate emissions will be controlled by an ESP. Mercury emissions will be controlled through a carbon injection system and the ESP system.

Electrostatic Precipitator

The ESP for the Osceola Power facility will be manufactured by Flakt, Inc. A drawing of the proposed ESP is provided in Appendix B. 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%

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LEGEND	
STRUCTURE	
1000	BOILER BUILDING
2000	TURBINE BUILDING
3000	CONTROL BLDG
4100	PRECIPITATOR
4200	I.D. FAN
4300	STUB-STACK
4500	CEMS BUILDING
5100	ASH STORAGE SILO
5200	BOTTOM ASH BIN
5300	CARBON SILO
6000	BIOMASS PILE (150,000 TON)
6100	TRUCK UNLOAD. HOPS./TIP.
6291	BIOMASS TRANSFER CONVEYOR (UNLOADING)
6292	TRANSFER CONVEYOR #2 (BOILER FEED)
6293	RECYCLE STOCK PILE CONVEYOR
6294	RETURN TRANSFER CONVEYOR (RECYCLE)
6300	TRANSFER TOWER
6400	CHAIN RECLAIMER
6401	CONVEYOR ELECTRICAL ROOM
6500	FUEL OIL TANK
6501	FUEL OIL UNLOADING
6600	STACKER (RADIAL)
6700	BAGASSE FEED CONVEY/PIPE BRIDGE
6800	TRUCK SCALES
6801	SCALE HOUSE
7100	COOLING TOWER
7101	CIRC. WATER PUMPS
7201	CONDENSATE RETURN TANK
7202	NEUTRALIZATION TANK
7203	R.O. PRODUCT WATER TANK
7204	DEMIN WATER STOR TANK
7205	UREA STORAGE
7400	FIREWATER PUMP STRUCTURE
7401	FIRE/FILTERED WATER STORAGE TANK
7600	WATER TREATMENT BUILDING
8100	ADMIN/WAREHOUSE (BY OTHERS)
9101	GENERATOR STEPUP TRANSFORMER
9102	AUX.POWER TRANSFORMER
9103	SUBSTATION (BY OTHERS)
9300	RAW WATER INTAKE STRUCTURE
9401	OIL/WATER SEPARATOR
9402	WASTEWATER DISCHARGE SUMP
9404	AIR COMPRESSORS AND RECEIVERS

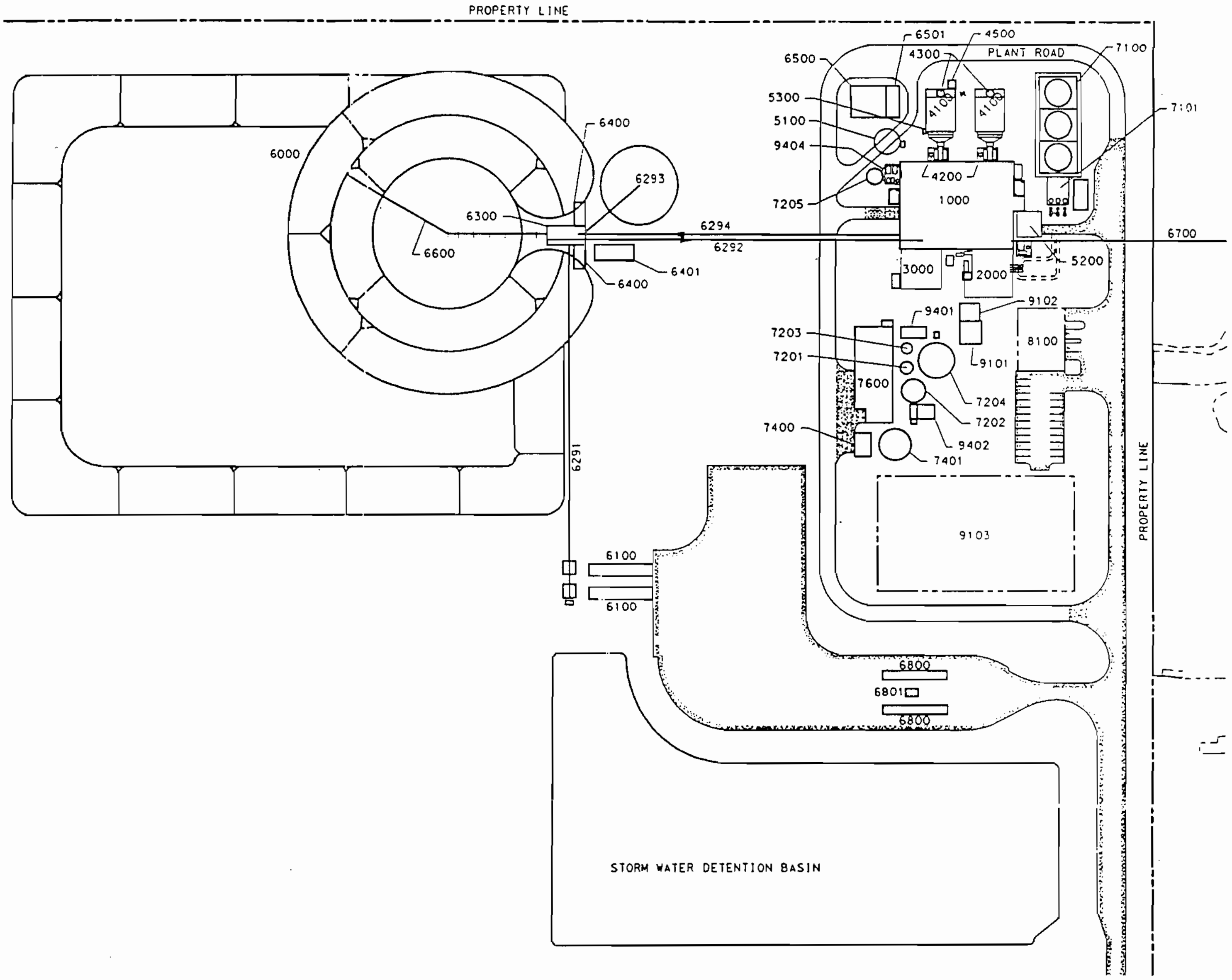

Figure 2-5
Plot Plan

Source: Bechtel, 1994.

NO_x Control System

A urea injection system manufactured by Nalco-Fueltech will be installed 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 will include 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 will supply urea to both boilers. Urea for injection into the boiler is drawn from the tank. Three injection zones will be used to provide injection at full and part load conditions. The first zone will have four injectors, and the second and third zones will have six injectors each, for a total of sixteen injectors. A schematic of the injector configuration is presented in Appendix B. Zone switching valves will direct the urea/carrier mixture to the appropriate injection zone.

Specifications for the urea injection system to meet the proposed NO_x emission rate of 0.116 lb/MMBtu when firing biomass fuels and 0.15 lb/MMBtu when firing coal are provided below (on a per boiler basis):

Urea injection rate - 65 gal/hr (max)
Ammonia Slip - Biomass - 25 ppm (max)
- Coal - 65 ppm (max)

Mercury Control System

The mercury control system will be similar to that installed on municipal waste incinerators. A volumetric feeder with integral supply hopper will meter activated carbon for injection at a point in the ductwork between the ESP and the ID fan. This will promote turbulent mixing and provide adequate residence time. A blower system will transport the carbon to the injection point. The

ESP will effectively capture the activated carbon particles along with the boiler flyash (which also contains some carbon). The system will be designed to inject up to 13 lb/hr of carbon into the flue gases of each boiler. A schematic of the carbon injection configuration is shown in Appendix B.

An elevation view of the carbon storage silo is presented in Appendix B. Carbon will be delivered to the facility by truck and pneumatically conveyed to the silo. The silo is divided into two compartments, one for each boiler. A dust collector sits atop the silo for control of dust emissions.

2.2.7 STACK PARAMETERS

Stack parameters for the cogeneration facility are presented in Table 2-3. Each of the two new boilers within the proposed facility will be served by a separate stack. The top of each stack will be 200 feet (ft) above ground. Each stack will be 8.0 ft in diameter. The locations of the two stacks are shown in Figure 2-5.

2.2.8 DISTILLATE OIL FUEL TANK

A fuel oil tank will be constructed to store the distillate fuel oil used for startup, shutdown and at other times as needed. The fuel oil tank will have a capacity of 50,000 gallons, and will be approximately 24 feet high with a 20 foot diameter. The tank will be of fixed roof design.

2.3 APPLICABILITY OF FEDERAL NEW SOURCE PERFORMANCE STANDARDS

2.3.1 NSPS FOR ELECTRIC UTILITY STEAM GENERATING UNITS

Based on the maximum heat input to the cogeneration facility boilers and the type of fuel burned, the boilers will be subject to the federal NSPS for electric utility steam generating units (40 CFR 60, Subpart Da). The Subpart Da standards are summarized in Table 2-4. For PM, the NSPS limits emissions to 0.03 lb/MMBtu when burning solid or liquid fuels. An opacity limit also applies, which limits opacity to 20 percent (6-minute average), except up to 27 percent opacity is allowed for one 6-minute period per hour.

In the case of SO_2, the proposed cogeneration units will be classified as "resource recovery units", since combustion of non-fossil fuels will be more than 75 percent on a quarterly (calendar) heat input basis. For such units, the NSPS limits SO_2 emissions to 1.2 lb/MMBtu based on a 30-day

Table 2-3. Stack Parameters for Osceola Power Cogeneration Facility

	Boilers (each)			Boiler House Baghouse	Fly Ash Silo Filter	Carbon Silo Filter
	Biomass	Oil	Coal			
Heat Input Rate (MMBtu/hr)	760	600	530	—	—	—
Stack Height (ft)	200	200	200	10	110	24
Stack Diam. (ft)	8.0	8.0	8.0	4.0 x 4.0	2.0 x 2.0	2.0 x 2.0
Gas Flowrate (acfm)	246,000 - 326,000	186,000 - 200,000	211,000 - 227,000	30,000	1,000	1,000
Gas Velocity (ft/s)	81.6 -108.1	66.3	70.0 - 75.3	31.3	4.2	4.2
Gas Temperature (°F)	295 - 340	295 - 350	295 - 350	80	100	80

Note: acfm = actual cubic feet per minute.
°F = degrees Fahrenheit.
ft = feet.
ft/s = feet per second.

Table 2-4. Federal NSPS for Electric Utility Steam-Generating Units Applicable to the Osceola Power Cogeneration Facility

Pollutant	Emission Limitation
Particulate Matter	Liquid fuel--0.03 lb/10^6 Btu Solid fuel--0.03 lb/10^6 Btu
Visible Emissions	20% opacity (6-minute average), except up to 27% opacity is allowed for one 6-minute period per hour
Sulfur Dioxide[a]	Resource Recovery Units--1.20 lb/10^6 Btu
Nitrogen Oxides[a]	Fuel Oil--0.30 lb/10^6 Btu Solid fuels: Bituminous coal--0.60 lb/10^6 Btu All other fuels--0.60 lb/10^6 Btu

Note: Emission limits for PM, NO_x, and SO_2 do not apply during periods of startup, shutdown, or malfunction.

[a] Compliance determined on a 30-day, rolling average basis.

Source: 40 CFR 60, Subpart Da.

rolling average. The proposed facility will comply with the NSPS for SO_2 by burning biomass, low sulfur coal with a maximum sulfur content of approximately 0.7 percent, and very low sulfur distillate fuel oil with a maximum sulfur content of 0.05 percent. Equivalent maximum SO_2 emission rates are 1.2 lb/MMBtu for coal and 0.05 lb/MMBtu for No. 2 fuel oil. Biomass has an inherently low sulfur content (i.e., average of about 0.009 percent by weight).

The NSPS for NO_x is 0.30 lb/MMBtu heat input for fuel oil firing and 0.60 lb/MMBtu for solid fuels, including bagasse, wood and coal. The proposed maximum NO_x emission rate for the facility for each fuel is lower than the NSPS. Compliance with the NO_x emissions limitation under Subpart Da is based on a 30-day rolling average.

Further requirements under 40 CFR 60 Subpart Da include emission monitoring. Continuous monitoring is required for opacity, NO_x, and carbon dioxide or oxygen. Specifically, a continuous opacity monitor must be installed at a point free of interference from water to monitor PM emissions. NO_x emissions must also be measured at the stack. Further, at the point NO_x emissions are monitored, oxygen or carbon dioxide must be monitored. The continuous monitoring systems are to be operated and data recorded during "all periods of operation including periods of startup, shutdown, malfunction or emergency conditions, except for continuous monitoring system breakdowns, repairs, calibration checks and span adjustments" [40 CFR 60.47a(e)].

2.3.2 NSPS FOR VOLATILE ORGANIC LIQUID STORAGE TANKS

The distillate fuel oil storage tank will be subject to the requirements of federal NSPS for Volatile Organic Liquid (VOL) storage vessels. The NSPS applies to all tanks of greater than 15,000 gallon capacity which will store any VOL and which was constructed after July 23, 1984. The NSPS requirements for such a tank, contained in 40 CFR 60.116b, states that the owner/operator of the storage tank must maintain information relating to the dimensions and capacity of the storage tank. This information must be readily accessible and be kept for the life of the source. Osceola Power will comply with this requirement by maintaining tank specification information on file at the plant site.

2.4 EMISSIONS OF REGULATED POLLUTANTS FROM BOILERS

2.4.1 CRITERIA/DESIGNATED POLLUTANTS

The emission limits for all criteria/designated pollutants emitted by the Osceola Power boilers are presented in Table 2-5. The emission limits in terms of lb/MMBtu are the same as currently permitted, with the following exceptions:

1. The maximum NO_x emission rate for biomass has been reduced to 0.116 lb/MMBtu (current limit is 0.12 lb/MMBtu), and the NO_x emission limit for coal firing has been reduced to 0.15 lb/MMBtu (current limit is 0.17 lb/MMBtu). These lower NO_x emission rates are achievable through the SNCR control system.

2. In the case of VOC emissions, specific emission limits for bagasse and wood waste are proposed. The limit for bagasse of 0.060 lb/MMBtu is equal to the current permit limit; the revised limit for wood waste of 0.040 lb/MMBtu is lower than the current permit limit. Based on boiler vendor information, these emission rates are achievable.

3. Lead emission limits have been revised based on updated emission factor information.

4. Mercury emissions for bagasse ($5.7x10^{-6}$ lb/MMBtu) have been reduced slightly from the current permitted level ($6.3x10^{-6}$ lb/MMBtu), while mercury emissions for wood waste remain unchanged. These mercury emission rates are achievable with the mercury control system.

5. Based on revised calculations, the emission limits for sulfuric acid mist have been revised. The revised limits are based on AP-42 which indicates the percentage of SO_2 that is emitted as SO_3, and then converting SO_3 to H_2SO_4.

Maximum hourly emissions from each of the Osceola Power boilers for each fuel are presented in Table 2-5. Emission factors and specific references are provided in Appendix A, Table A-1. As shown, the maximum hourly emissions occur when burning either biomass or coal. The maximum hourly emissions are generally higher than currently permitted due to the increase in the maximum heat input rate to the boilers.

Table 2–5. Maximum Hourly Emissions for Osceola Power Cogeneration Facility (per boiler).

	Biomass			No. 2 Fuel Oil			Coal			
Regulated Pollutant	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)	Maximum Emissions for any fuel (lb/hr)
Particulate (TSP)	0.03	760	22.8	0.03	600	18.0	0.03	530	15.9	22.8
Particulate (PM10)	0.03	760	22.8	0.03	600	18.0	0.03	530	15.9	22.8
Sulfur dioxide[a]	0.10	760	76.0	0.05	600	30.0	1.2	530	636.0	636.0
Nitrogen oxides[b]	0.116	760	88.2	0.12	600	72.0	0.15	530	79.5	88.2
Carbon monoxide[c]	0.35	760	266.0	0.20	600	120.0	0.20	530	106.0	266.0
VOC– Bagasse	0.060	760	45.6	0.03	600	18.0	0.03	530	15.9	45.6
Wood Waste	0.040	760	30.4							
Lead	2.7E–06	760	0.0021	8.9E–07	600	0.0005	5.1E–06	530	0.0027	0.0027
Mercury– Bagasse	5.7E–06	760	0.0043	2.4E–06	600	0.0014	8.4E–06	530	0.0045	0.0045
Wood Waste	2.9E–07	760	0.00022							
Beryllium	– –	– –	– –	3.5E–07	600	0.0002	5.9E–06	530	0.0031	0.0031
Fluorides	– –	– –	– –	6.27E–06	600	0.0038	0.024	530	12.7	12.72
Sulfuric acid mist	0.0049	760	3.72	0.0025	600	1.5	0.010	530	5.30	5.30
Total reduced sulfur	– –	– –	– –	– –	– –	– –	– –	– –	– –	– –
Asbestos	– –	– –	– –	– –	– –	– –	– –	– –	– –	– –
Vinyl chloride	– –	– –	– –	– –	– –	– –	– –	– –	– –	– –

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[a] 24–hour average.

[b] 30–day rolling average.

[c] 8–hour average.

The total maximum annual emissions for each pollutant from both boilers is presented in Table 2-6. These are based upon the same emission factors as presented in Table 2-5. The total maximum annual emission rate for each pollutant is based upon the worst-case fuel operating scenario and is identified in the far right column of Table 2-6.

The annual SO_2 emissions presented in Table 2-6 include the worst-case scenario of 5.4 percent coal burning in any one year, with remaining heat input from biomass. In the case of mercury emissions, in order to meet the proposed mercury emission limit (in TPY) under certain fuel firing scenarios, the annual firing of bagasse and/or coal may need to be limited due to the higher emission factors for bagasse and coal compared to wood waste firing. The limits on firing of different fuels will depend upon the mix of fuels, actual emission factors, and the total heat input in any given year. Once operation of the facility commences, a test program will be undertaken by Osceola Power to establish actual mercury emission factors for each fuel. Based on the established emission factors, a fuel management plan will be implemented to insure the 0.0168 TPY mercury emission limit is not exceeded. The fuel management plan will be submitted to FDEP's West Palm Beach office and to the Palm Beach County Health Unit for review.

2.4.2 EMISSIONS OF HAZARDOUS AIR POLLUTANTS

Emission factors for hazardous air pollutants (HAPS) were obtained from various sources, as shown in Appendix A, Table A-2. Considerable effort was undertaken to attempt to identify an emission factor for all HAPs. Many factors were available for wood waste firing as obtained from AP-42, NCASI technical bulletins, and other sources. Emission factors for bagasse were assumed to be the same as for wood waste firing. The HAP emission factors are shown in Table 2-7. Maximum hourly emissions of HAPs are presented in Table 2-7. Estimates of maximum annual HAP emissions are presented in Table 2-8.

The estimated HAP emissions also account for the possibility that up to 2.4 percent treated wood may be present in the wood-waste stream. Osceola Power will not knowingly accept treated wood. Nonetheless, the estimated emissions for arsenic, chromium, and hexavalent chromium (Cr^{+6}) are based on 2.4 percent treated wood in the wood-waste stream. Calculations and emission factors are presented in Tables 2-9 and 2-10. These emission factors are utilized in Tables 2-7 and 2-8.

Table 2–6. Maximum Annual Emissions for Osceola Power L. P. Cogeneration Facility (total all boilers)

	Biomass			No. 2 Fuel			Coal			Total
Regulated Pollutant	Emission Factor (lb/MMBtu)	Activity Factor (E12 Btu/yr)	Annual Emissions (TPY)	Emission Factor (lb/MMBtu)	Activity Factor (E12 Btu/yr)	Annual Emissions (TPY)	Emission Factor (lb/MMBtu)	Activity Factor (E12 Btu/yr)	Annual Emissions (TPY)	Annual Emissions (TPY)
		Normal Operations								
Particulate (TSP)	0.03	8.208	123.12	--	--	--	--	--	--	123.12 a
Particulate (PM10)	0.03	8.208	123.12	--	--	--	--	--	--	123.12 a
Sulfur dioxide	0.02	8.208	82.08	--	--	--	--	--	--	82.08
Nitrogen oxides	0.116	8.208	476.06	--	--	--	--	--	--	476.06
Carbon monoxide	0.35	8.208	1,436.40	--	--	--	--	--	--	1,436.40 a
VOC– Bagasse	0.060	5.499 b	164.98	--	--	--	--	--	--	219.15 a
Wood waste	0.040	2.709 c	54.17							
Lead	2.7E–06	8.208	0.011	--	--	--	--	--	--	0.011
Mercury– Bagasse	5.7E–06	5.499 b	0.01567	--	--	--	--	--	--	0.0161
Wood waste	2.9E–07	2.709 c	0.00039							
Beryllium	--	--	--	--	--	--	--	--	--	--
Fluorides	--	--	--	--	--	--	--	--	--	--
Sulfuric acid mist	0.00098	8.208	4.02	--	--	--	--	--	--	4.02
Total reduced sulfur	--	--	--	--	--	--	--	--	--	--
Asbestos	--	--	--	--	--	--	--	--	--	--
Vinyl Chloride	--	--	--	--	--	--	--	--	--	--
		25% Oil Firing								
Particulate (TSP)	0.03	5.793	86.90	0.03	1.931	28.97	--	--	--	115.86
Particulate (PM10)	0.03	5.793	86.90	0.03	1.931	28.97	--	--	--	115.86
Sulfur dioxide	0.02	5.793	57.93	0.05	1.931	48.28	--	--	--	106.21
Nitrogen oxides	0.116	5.793	335.99	0.12	1.931	115.86	--	--	--	451.85
Carbon monoxide	0.35	5.793	1,013.78	0.20	1.931	193.10	--	--	--	1,206.88
VOC– Bagasse	0.060	3.881 b	116.44	0.03	1.931	28.97	--	--	--	183.64
Wood waste	0.040	1.912 c	38.23							
Lead	2.7E–06	5.793	0.008	8.9E–07	1.931	0.001	--	--	--	0.009
Mercury– Bagasse	5.7E–06	3.823 b	0.01090	2.4E–06	1.931	0.0023	--	--	--	0.0135
Wood waste	2.9E–07	1.912 c	0.00028							
Beryllium	--	--	--	3.5E–07	1.931	0.0003	--	--	--	0.00034
Fluorides	--	--	--	6.27E–06	1.931	0.0061	--	--	--	0.006
Sulfuric acid mist	0.00098	5.793	2.84	0.0025	1.931	2.37	--	--	--	5.20
Total reduced sulfur	--	--	--	--	--	--	--	--	--	--
Asbestos	--	--	--	--	--	--	--	--	--	--
Vinyl Chloride	--	--	--	--	--	--	--	--	--	--
		5.4% Coal Firing								
Particulate (TSP)	0.03	7.661	114.92	--	--	--	0.03	0.4373	6.56	121.47
Particulate (PM10)	0.03	7.661	114.92	--	--	--	0.03	0.4373	6.56	121.47
Sulfur dioxide	0.02	7.661	76.61	--	--	--	1.2	0.4373	262.38	338.99 a
Nitrogen oxides	0.116	7.661	444.34	--	--	--	0.15	0.4373	32.80	477.14 a
Carbon monoxide	0.35	7.661	1,340.68	--	--	--	0.20	0.4373	43.73	1,384.41
VOC– Bagasse	0.060	5.133 b	153.99	--	--	--	0.03	0.4373	6.56	160.55
Wood waste	0.040	2.528 c	50.56							
Lead	2.7E–06	7.661	0.010	--	--	--	5.1E–06	0.4373	0.0011	0.011 a
Mercury– Bagasse	5.7E–06	5.133 b	0.01463	--	--	--	8.4E–06	0.4373	0.00184	0.0168 a
Wood waste	2.9E–07	2.528 c	0.00037							
Beryllium	--	--	--	--	--	--	5.9E–06	0.4373	0.0013	0.0013 a
Fluorides	--	--	--	--	--	--	0.024	0.4373	5.25	5.25 a
Sulfuric acid mist	0.00098	7.661	3.75	--	--	--	0.010	0.4373	2.25	6.00 a
Total reduced sulfur	--	--	--	--	--	--	--	--	--	--
Asbestos	--	--	--	--	--	--	--	--	--	--
Vinyl Chloride	--	--	--	--	--	--	--	--	--	--

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[a] Denotes maximum annual emissions for any fuel scenario.
[b] Represents 67% of total heat input.
[c] Represents 33% of total heat input.

Table 2-7. Maximum Hourly Emissions of Hazardous Air Pollutants for Osceola Power Cogeneration Facility (per boiler).

Hazardous Air Pollutant	Biomass			No. 2 Fuel Oil			Coal			Maximum Hourly Emissions For Any Fuel (lb/hr)
	Emission Factor (lb/MMBtu)	Activity Factor (MMBtu/hr)	Hourly Emissions (lb/hr)	Emission Factor (lb/MMBtu)	Activity Factor (MMBtu/hr)	Hourly Emissions (lb/hr)	Emission Factor (lb/MMBtu)	Activity Factor (MMBtu/hr)	Hourly Emissions (lb/hr)	
Acetaldehyde	7.8E-04	760	0.59	--	--	--	--	--	--	0.59
Acetophenone	3.7E-06	760	0.0028	--	--	--	--	--	--	0.0028
Acrolein	6.5E-05	760	0.049	--	--	--	--	--	--	0.049
Antimony	ND	--	--	2.4E-07	600	0.00014	3.5E-05	530	0.019	0.019
Arsenic	1.3E-04	760	0.10	4.2E-08	600	2.52E-05	5.4E-06	530	0.0029	0.10
Benzene	1.3E-03	760	0.99	--	--	--	--	--	--	0.99
Cadmium	8.4E-07	760	0.00064	1.1E-07	600	6.60E-05	4.3E-07	530	0.00023	0.00064
Carbon Disulfide	1.3E-04	760	0.10	--	--	--	--	--	--	0.099
Carbon Tetrachloride	6.0E-06	760	0.0046	--	--	--	--	--	--	0.0046
Chlorine	9.2E-04	760	0.70	--	--	--	--	--	--	0.70
Chloroform	4.7E-05	760	0.036	--	--	--	--	--	--	0.036
Chromium	1.6E-04	760	0.12	6.7E-07	600	0.00040	1.6E-05	530	0.0085	0.12
Chromium (VI)	3.2E-05	760	0.024	1.3E-07	600	7.80E-05	3.1E-06	530	0.0016	0.024
Cobalt	1.5E-07	760	0.00011	1.2E-05	600	0.0070	7.2E-05	530	0.038	0.038
Cumene	1.8E-05	760	0.014	--	--	--	--	--	--	0.014
Di - n - Butyl Phthalate	5.8E-05	760	0.044	--	--	--	--	--	--	0.044
Ethyl Benzene	3.9E-06	760	0.0030	--	--	--	--	--	--	0.0030
Formaldehyde	1.3E-03	760	0.99	4.1E-04	600	0.25	2.2E-04	530	0.12	0.99
n Hexane	5.5E-04	760	0.42	--	--	--	--	--	--	0.42
Hydrogen Chloride	5.6E-04	760	0.43	6.4E-04	600	0.38	7.9E-02	530	41.87	41.9
Manganese	9.5E-05	760	0.072	1.4E-07	600	8.40E-05	3.1E-07	530	0.00016	0.072
Methanol	1.5E-03	760	1.14	--	--	--	--	--	--	1.14
Methyl Ethyl Ketone	1.2E-05	760	0.0091	--	--	--	--	--	--	0.0091
Methyl Isobutyl Ketone	8.6E-04	760	0.65	--	--	--	--	--	--	0.65
Methylene Chloride	1.5E-03	760	1.14	--	--	--	--	--	--	1.14
Napthalene	5.9E-04	760	0.45	--	--	--	--	--	--	0.45
Nickel	6.3E-06	760	0.0048	1.7E-06	600	0.0010	1.0E-05	530	0.005	0.0053
Phenols	4.1E-05	760	0.031	--	--	--	--	--	--	0.031
Phosphorous	1.6E-06	760	0.0012	5.8E-05	600	0.035	8.6E-04	530	0.46	0.46
POM (Polycyclic Organic Matter)	2.2E-07	760	0.00017	8.4E-06	--	--	--	--	--	0.00017
Selenium	3.8E-06	760	0.0029	3.8E-07	600	0.00023	5.3E-05	530	0.028	0.028
Styrene	1.5E-05	760	0.011	--	--	--	--	--	--	0.011
2,3,7,8 Tetrachlorodibenzo-p-dioxin	6.0E-12	760	4.56E-09	--	--	--	--	--	--	4.56E-09
Toluene	9.0E-05	760	0.068	--	--	--	--	--	--	0.068
1,1,1 Trichlorethane	1.7E-04	760	0.13	--	--	--	--	--	--	0.13
Trichloroethylene	7.6E-06	760	0.0058	--	--	--	--	--	--	0.006
m & p Xylene	7.8E-06	760	0.0059	--	--	--	--	--	--	0.0059
o Xylene	2.6E-06	760	0.0020	--	--	--	--	--	--	0.0020

Source: KBN, 1995.

Table 2-8. Maximum Annual Emissions of Hazardous Air Pollutants for Osceola Power Cogeneration Facility (total all boilers)

	Biomass			No. 2 Fuel Oil			Coal			
Hazardous Air Pollutant	Emission Factor (lb/MMBtu)	Activity Factor (E12 Btu/yr)	Annual Emissions (TPY)	Emission Factor (lb/MMBtu)	Activity Factor (E12 Btu/yr)	Annual Emissions (TPY)	Emission Factor (lb/MMBtu)	Activity Factor (E12 Btu/yr)	Annual Emissions (TPY)	Total Annual Emissions (TPY)
		Normal Operations								
Acetaldehyde	7.8E-04	8.208	3.20	--	--	--	--	--	--	3.20 *
Acetophenone	3.7E-06	8.208	0.015	--	--	--	--	--	--	0.015 *
Acrolein	6.5E-05	8.208	0.27	--	--	--	--	--	--	0.27 *
Antimony	ND	--	--	--	--	--	--	--	--	--
Arsenic	6.97E-05	8.208	0.286	--	--	--	--	--	--	0.286 *
Benzene	1.3E-03	8.208	5.34	--	--	--	--	--	--	5.34 *
Cadmium	8.4E-07	8.208	0.0034	--	--	--	--	--	--	0.0034 *
Carbon Disulfide	1.3E-04	8.208	0.53	--	--	--	--	--	--	0.53 *
Carbon Tetrachloride	6.0E-06	8.208	0.025	--	--	--	--	--	--	0.025 *
Chlorine	9.2E-04	8.208	3.78	--	--	--	--	--	--	3.78 *
Chloroform	4.7E-05	8.208	0.19	--	--	--	--	--	--	0.19 *
Chromium	8.27E-05	8.208	0.339	--	--	--	--	--	--	0.339 *
Chromium (VI)	1.65E-05	8.208	0.068	--	--	--	--	--	--	0.068 *
Cobalt	1.5E-07	8.208	0.00062	--	--	--	--	--	--	0.00062
Cumene	1.8E-05	8.208	0.074	--	--	--	--	--	--	0.074 *
Di - n - Butyl Phthalate	5.8E-05	8.208	0.24	--	--	--	--	--	--	0.24 *
Ethyl Benzene	3.9E-06	8.208	0.016	--	--	--	--	--	--	0.016 *
Formaldehyde	1.3E-03	8.208	5.34	--	--	--	--	--	--	5.34 *
n Hexane	5.5E-04	8.208	2.26	--	--	--	--	--	--	2.26 *
Hydrogen Chloride	5.6E-04	8.208	2.30	--	--	--	--	--	--	2.30
Manganese	9.5E-05	8.208	0.39	--	--	--	--	--	--	0.39 *
Methanol	1.5E-03	8.208	6.16	--	--	--	--	--	--	6.16 *
Methyl Ethyl Ketone	1.2E-05	8.208	0.049	--	--	--	--	--	--	0.049 *
Methyl Isobutyl Ketone	8.6E-04	8.208	3.53	--	--	--	--	--	--	3.53 *
Methylene Chloride	1.5E-03	8.208	6.16	--	--	--	--	--	--	6.16 *
Napthalene	5.9E-04	8.208	2.42	--	--	--	--	--	--	2.42 *
Nickel	6.3E-06	8.208	0.026	--	--	--	--	--	--	0.026
Phenols	4.1E-05	8.208	0.17	--	--	--	--	--	--	0.17 *
Phosphorous	1.6E-06	8.208	0.0066	--	--	--	--	--	--	0.0066
POM (Polycyclic Organic Matter)	2.2E-07	8.208	0.00090	--	--	--	--	--	--	0.00090 *
Selenium	3.8E-06	8.208	0.016	--	--	--	--	--	--	0.016
Styrene	1.5E-05	8.208	0.062	--	--	--	--	--	--	0.062 *
2,3,7,8 Tetrachlorodibenzo-p-dioxin	6.0E-12	8.208	2.46E-08	--	--	--	--	--	--	2.46E-08 *
Toluene	9.0E-05	8.208	0.37	--	--	--	--	--	--	0.37 *
1,1,1 Trichlorethane	1.7E-04	8.208	0.70	--	--	--	--	--	--	0.70 *
Trichloroethylene	7.6E-06	8.208	0.031	--	--	--	--	--	--	0.031 *
m & p Xylene	7.8E-06	8.208	0.032	--	--	--	--	--	--	0.032 *

Table 2−8. Maximum Annual Emissions of Hazardous Air Pollutants for Osceola Power Cogeneration Facility (total all boilers)

Hazardous Air Pollutant	Biomass			No. 2 Fuel Oil			Coal			Total Annual Emissions (TPY)
	Emission Factor (lb/MMBtu)	Activity Factor (E12 Btu/yr)	Annual Emissions (TPY)	Emission Factor (lb/MMBtu)	Activity Factor (E12 Btu/yr)	Annual Emissions (TPY)	Emission Factor (lb/MMBtu)	Activity Factor (E12 Btu/yr)	Annual Emissions (TPY)	
o Xylene	2.6E−06	8.208	0.011	−−	−−	−−	−−	−−	−−	0.011 *
		25% Oil Firing								
Acetaldehyde	7.8E−04	5.793	2.26	−−	−−	−−	−−	−−	−−	2.26
Acetophenone	3.7E−06	5.793	0.011	−−	−−	−−	−−	−−	−−	0.011
Acrolein	6.5E−05	5.793	0.19	−−	−−	−−	−−	−−	−−	0.19
Antimony	ND	−−	−−	2.4E−06	1.931	0.0023	−−	−−	−−	0.0023
Arsenic	6.97E−05	5.793	0.202	4.2E−08	1.931	4.06E−05	−−	−−	−−	0.20
Benzene	1.3E−03	5.793	3.77	−−	−−	−−	−−	−−	−−	3.77
Cadmium	8.4E−07	5.793	0.0024	1.1E−07	1.931	0.00011	−−	−−	−−	0.0025
Carbon Disulfide	1.3E−04	5.793	0.38	−−	−−	−−	−−	−−	−−	0.38
Carbon Tetrachloride	6.0E−06	5.793	0.017	−−	−−	−−	−−	−−	−−	0.017
Chlorine	9.2E−04	5.793	2.66	−−	−−	−−	−−	−−	−−	2.66
Chloroform	4.7E−05	5.793	0.14	−−	−−	−−	−−	−−	−−	0.14
Chromium	8.27E−05	5.793	0.240	6.7E−07	1.931	0.00065	−−	−−	−−	0.240
Chromium (VI)	1.65E−05	5.793	0.048	1.3E−07	1.931	0.00013	−−	−−	−−	0.048
Cobalt	1.5E−07	5.793	0.00043	1.2E−05	1.931	0.011	−−	−−	−−	0.012
Cumene	1.8E−05	5.793	0.052	−−	−−	−−	−−	−−	−−	0.052
Di − n − Butyl Phthalate	5.8E−05	5.793	0.17	−−	−−	−−	−−	−−	−−	0.17
Ethyl Benzene	3.9E−06	5.793	0.011	−−	−−	−−	−−	−−	−−	0.011
Formaldehyde	1.3E−03	5.793	3.77	4.1E−04	1.931	0.39	−−	−−	−−	4.16
n Hexane	5.5E−04	5.793	1.59	−−	−−	−−	−−	−−	−−	1.59
Hydrogen Chloride	5.6E−04	5.793	1.62	6.4E−04	1.931	0.61	−−	−−	−−	2.24
Manganese	9.5E−05	5.793	0.28	1.4E−07	1.931	0.00014	−−	−−	−−	0.28
Methanol	1.5E−03	5.793	4.34	−−	−−	−−	−−	−−	−−	4.34
Methyl Ethyl Ketone	1.2E−05	5.793	0.035	−−	−−	−−	−−	−−	−−	0.035
Methyl Isobutyl Ketone	8.6E−04	5.793	2.49	−−	−−	−−	−−	−−	−−	2.49
Methylene Chloride	1.5E−03	5.793	4.34	−−	−−	−−	−−	−−	−−	4.34
Napthalene	5.9E−04	5.793	1.71	−−	−−	−−	−−	−−	−−	1.71
Nickel	6.3E−06	5.793	0.018	1.7E−06	1.931	0.0016	−−	−−	−−	0.020
Phenols	4.1E−05	5.793	0.12	−−	−−	−−	−−	−−	−−	0.12
Phosphorous	1.6E−06	5.793	0.0046	5.8E−06	1.931	0.0056	−−	−−	−−	0.010
POM (Polycyclic Organic Matter)	2.2E−07	5.793	0.00064	5.8E−06	−−	−−	−−	−−	−−	0.00064
Selenium	3.8E−06	5.793	0.011	3.8E−07	1.931	0.00037	−−	−−	−−	0.011
Styrene	1.5E−05	5.793	0.043	−−	−−	−−	−−	−−	−−	0.043
2,3,7,8 Tetrachlorodibenzo−p−dioxin	6.0E−12	5.793	1.74E−08	−−	−−	−−	−−	−−	−−	1.74E−08
Toluene	9.0E−05	5.793	0.26	−−	−−	−−	−−	−−	−−	0.26
1,1,1 Trichlorethane	1.7E−04	5.793	0.49	−−	−−	−−	−−	−−	−−	0.49

Table 2-8. Maximum Annual Emissions of Hazardous Air Pollutants for Osceola Power Cogeneration Facility (total all boilers)

	Biomass			No. 2 Fuel Oil			Coal			
Hazardous Air Pollutant	Emission Factor (lb/MMBtu)	Activity Factor (E12 Btu/yr)	Annual Emissions (TPY)	Emission Factor (lb/MMBtu)	Activity Factor (E12 Btu/yr)	Annual Emissions (TPY)	Emission Factor (lb/MMBtu)	Activity Factor (E12 Btu/yr)	Annual Emissions (TPY)	Total Annual Emissions (TPY)
Trichloroethylene	7.6E-06	5.793	0.022	--	--	--	--	--	--	0.022
m & p Xylene	7.8E-06	5.793	0.023	--	--	--	--	--	--	0.023
o Xylene	2.6E-06	5.793	0.0075	--	--	--	--	--	--	0.0075
		5.4 % Coal Firing								
Acetaldehyde	7.8E-04	7.661	2.99	--	--	--	--	--	--	2.99
Acetophenone	3.7E-06	7.661	0.014	--	--	--	--	--	--	0.014
Acrolein	6.5E-05	7.661	0.25	--	--	--	--	--	--	0.25
Antimony	ND	--	--	--	--	--	3.5E-05	0.437	0.0076	0.0076 *
Arsenic	6.97E-05	7.661	0.2670	--	--	--	5.4E-06	0.437	0.0012	0.2682
Benzene	1.3E-03	7.661	4.98	--	--	--	--	--	--	4.98
Cadmium	8.4E-07	7.661	0.0032	--	--	--	4.3E-07	0.437	9.40E-05	0.0033
Carbon Disulfide	1.3E-04	7.661	0.50	--	--	--	--	--	--	0.50
Carbon Tetrachloride	6.0E-06	7.661	0.023	--	--	--	--	--	--	0.023
Chlorine	9.2E-04	7.661	3.524	--	--	--	--	--	--	3.52
Chloroform	4.7E-05	7.661	0.18	--	--	--	--	--	--	0.18
Chromium	8.27E-05	7.661	0.317	--	--	--	1.6E-05	0.4373	0.0035	0.320
Chromium (VI)	1.65E-05	7.661	0.063	--	--	--	3.1E-06	0.4373	0.00068	0.064
Cobalt	1.5E-07	7.661	0.00057	--	--	--	7.2E-05	0.4373	0.016	0.016 *
Cumene	1.8E-05	7.661	0.069	--	--	--	--	--	--	0.069
Di - n - Butyl Phthalate	5.8E-05	7.661	0.22	--	--	--	--	--	--	0.22
Ethyl Benzene	3.9E-06	7.661	0.015	--	--	--	--	--	--	0.015
Formaldehyde	1.3E-03	7.661	4.98	--	--	--	2.2E-04	0.4373	0.048	5.03
n Hexane	5.5E-04	7.661	2.11	--	--	--	--	--	--	2.11
Hydrogen Chloride	5.6E-04	7.661	2.15	--	--	--	7.9E-02	0.4373	17.27	19.42 *
Manganese	9.5E-05	7.661	0.36	--	--	--	3.1E-07	0.4373	6.78E-05	0.36
Methanol	1.5E-03	7.661	5.75	--	--	--	--	--	--	5.75
Methyl Ethyl Ketone	1.2E-05	7.661	0.046	--	--	--	--	--	--	0.046
Methyl Isobutyl Ketone	8.6E-04	7.661	3.29	--	--	--	--	--	--	3.29
Methylene Chloride	1.5E-03	7.661	5.75	--	--	--	--	--	--	5.75
Napthalene	5.9E-04	7.661	2.26	--	--	--	--	--	--	2.26
Nickel	6.3E-06	7.661	0.024	--	--	--	1.0E-05	0.4373	0.0022	0.026 *
Phenols	4.1E-05	7.661	0.16	--	--	--	--	--	--	0.16
Phosphorous	1.6E-06	7.661	0.0061	--	--	--	8.6E-04	0.4373	0.19	0.194 *
POM (Polycyclic Organic Matter)	2.2E-07	7.661	0.00084	--	--	--	--	--	--	0.00084
Selenium	3.8E-06	7.661	0.015	--	--	--	5.3E-05	0.437	0.012	0.026 *
Styrene	1.5E-05	7.661	0.057	--	--	--	--	--	--	0.057
2,3,7,8 Tetrachlorodibenzo-p-dioxin	6.0E-12	7.661	2.30E-08	--	--	--	--	--	--	2.30E-08

Table 2–8. Maximum Annual Emissions of Hazardous Air Pollutants for Osceola Power Cogeneration Facility (total all boilers)

	Biomass			No. 2 Fuel Oil			Coal			
Hazardous Air Pollutant	Emission Factor (lb/MMBtu)	Activity Factor (E12 Btu/yr)	Annual Emissions (TPY)	Emission Factor (lb/MMBtu)	Activity Factor (E12 Btu/yr)	Annual Emissions (TPY)	Emission Factor (lb/MMBtu)	Activity Factor (E12 Btu/yr)	Annual Emissions (TPY)	Total Annual Emissions (TPY)
Toluene	9.0E–05	7.661	0.34	--	--	--	--	--	--	0.34
1,1,1 Trichlorethane	1.7E–04	7.661	0.65	--	--	--	--	--	--	0.65
Trichloroethylene	7.6E–06	7.661	0.029	--	--	--	--	--	--	0.029
m & p Xylene	7.8E–06	7.661	0.030	--	--	--	--	--	--	0.030
o Xylene	2.6E–06	7.661	0.010	--	--	--	--	--	--	0.010

a Denotes maximum annual emissions for any fuel scenario.

Note: UD = undetectable levels in gas stream.

Table 2–9. Maximum Concentrations of Metals in Wood Waste Due To Treated Wood

WOOD WASTE PARAMETERS	
Total Biomass	965,647 tons
Total Wood waste	50%
Total Wood waste	482,824 tons
CLEAN WOOD WASTE PARAMETERS	
Total Clean Wood Waste	97.6% 471,236 tons
Arsenic content (1 ppm)	0.47 tons
Chromium content (3 ppm)	1.41 tons
Copper content (15 ppm)	7.07 tons
TREATED WOOD PARAMETERS	
Percent of total wood amount	2.4%
Total treated wood amount	11,588 tons
Treated wood density	26.3 lb/ft^3
CCA in treated wood	0.47 lb/ft^3 0.01787 lb CCA/lb treated wood
Total CCA in treated wood	207.1 tons
Total CCA components in treated wood	
Arsenic (13%)	26.9 tons
Chromium (15%)	31.1 tons
Copper (9%)	18.6 tons
WOOD WASTE CONCENTRATIONS	
Total CCA components in wood waste (clean wood plus treated wood):	
Arsenic	27.4 tons
Chromium	32.5 tons
Copper	25.7 tons
Arsenic	56.7 ppm
Chromium	67.3 ppm
Copper	53.2 ppm

Table 2–10. Maximum Emissions Of Metals Due To Treated Wood Waste Burning

Parameter	Annual Average		Maximum Short–Term	
BIOMASS PARAMETERS				
Total biomass heat input	8.208E+06	MMBtu/yr	760	MMBtu/hr
Total biomass	965,647	tons/yr	178,824	lb/hr[a]
Total bagasse percentage	50%		0%	
Total bagasse amount	482,824	tons/yr	0	lb/hr
Total wood waste percentage	50%		100%	
Total wood waste amount	482,824	tons/yr	178,824	lb/hr
BAGASSE CONCENTRATIONS[b]				
Arsenic	1.0	ppm	1.0	ppm
Chromium	3.0	ppm	3.0	ppm
Copper	15.0	ppm	15.0	ppm
WOOD WASTE CONCENTRATIONS				
Total CCA components in wood waste (clean wood plus treated wood):				
Arsenic	56.7	ppm	56.7	ppm
Chromium	67.3	ppm	67.3	ppm
Copper	53.2	ppm	53.2	ppm
CCA COMPONENTS IN BIOMASS				
Arsenic: Bagasse	0.48	tons/yr	0	lb/hr
Wood Waste	27.38	tons/yr	10.14	lb/hr
Total	27.86	tons/yr	10.14	lb/hr
Chromium: Bagasse	1.45	tons/yr	0	lb/hr
Wood Waste	32.49	tons/yr	12.03	lb/hr
Total	33.94	tons/yr	12.03	lb/hr
Copper: Bagasse	7.24	tons/yr	0	lb/hr
Wood Waste	25.69	tons/yr	9.51	lb/hr
Total	32.93	tons/yr	9.51	lb/hr
EMISSIONS OF CCA[c]				
Arsenic	0.279	tons/yr	0.101	lb/hr
Chromium	0.339	tons/yr	0.120	lb/hr
Chromium +6[d]	0.068	tons/yr	0.024	lb/hr
Copper	0.329	tons/yr	0.095	lb/hr
Arsenic	6.79E–05	lb/MMBtu	1.33E–04	lb/MMBtu
Chromium	8.27E–05	lb/MMBtu	1.58E–04	lb/MMBtu
Chromium +6[d]	1.65E–05	lb/MMBtu	3.17E–05	lb/MMBtu
Copper	8.02E–05	lb/MMBtu	1.25E–04	lb/MMBtu

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[a] Based on conservative heating value for wood waste of 4,250 Btu/lb.

[b] Based on typical conentrations occurring in biomass.

[c] Assumes all of CCA exits boiler in flue gases, and ESP has 99% removal efficiency.

[d] Assumes 20% of total chromium is hexavalent.

2.4.3 EMISSIONS OF OTHER FLORIDA AIR TOXICS

Emission factors for other pollutants identified as an air toxic under Florida's air toxics permitting strategy are presented in Table 2-11. The emission factors were obtained from various sources, as shown in Appendix A, Table A-3. Considerable effort was undertaken to attempt to identify an emission factor for all Florida air toxics (FATs) which were not already identified as HAPs. Many factors were available for wood waste firing as obtained from AP-42, NCASI technical bulletins, and other sources. Emission factors for bagasse were assumed to be the same as for wood waste firing.

Maximum hourly emissions of FATs are presented in Table 2-11. Estimates of maximum annual FAT emissions are presented in Table 2-12.

The estimated HAP emissions also account for the possibility that up to 2.4 percent treated wood may be present in the wood-waste stream. The estimated emissions for copper are based on 2.4 percent treated wood in the wood-waste stream. Calculations and the emission factors for copper are presented in Tables 2-9 and 2-10. These emission factors are utilized in Tables 2-11 and 2-12.

Residual ammonia emissions are associated with use of a selective non-catalytic reduction (SNCR) system for NO_x emission control. For the Osceola Power boilers, a maximum of 25 ppm NH_3 slip is indicated by the SNCR vendor, and this results in maximum NH_3 emissions of 11.4 lb/hr per boiler when burning biomass and No. 2 fuel oil. This is equivalent to 0.015 lb/MMBtu heat input. For coal burning, a higher ammonia slip of 65 ppm indicated due to the higher ammonia injection rate required to achieve the NO_x emission limit. This results in ammonia emissions of 25.4 lb/hr per boiler. This is equivalent to 0.048 lb/MMBtu heat input.

2.4.4 TREATED WOOD BURNING

Although Osceola Power will not knowingly accept any treated wood for fuel at the facility, it is recognized that some small amount of treated wood may be present in the wood waste stream.

Table 2-11. Maximum Hourly Emissions of Florida Air Toxics for Osceola Power Cogeneration Facility (per boiler).

	Biomass			No. 2 Fuel Oil			Coal			Maximum
Florida Air Toxic	Emission Factor (lb/MMBtu)	Activity Factor (MMBtu/hr)	Hourly Emissions (lb/hr)	Emission Factor (lb/MMBtu)	Activity Factor (MMBtu/hr)	Hourly Emissions (lb/hr)	Emission Factor (lb/MMBtu)	Activity Factor (MMBtu/hr)	Hourly Emissions (lb/hr)	Emission For Any Fuel (lb/hr)
Acetone	3.8E-04	760	0.29	--	--	--	--	--	--	0.29
Ammonia	1.50E-02	760	11.4	1.50E-02	600	9.00	0.048	530	25.44	25.4
Barium	5.20E-06	760	0.0040	6.69E-07	600	0.00040	7.44E-05	530	0.039	0.039
Benzo(a)anthracene	7.53E-07	760	0.00057	--	--	--	--	--	--	0.00057
Benzo(a)pyrene	3.53E-08	760	2.68E-05	--	--	--	--	--	--	2.68E-05
Bromine	4.59E-05	760	0.035	6.97E-07	600	0.00042	7.90E-05	530	0.042	0.04
Chrysene	3.53E-05	760	0.027	--	--	--	--	--	--	0.027
Copper - Maximum	1.25E-04	760	0.095	4.20E-05	600	0.025	1.71E-04	530	0.091	0.095
Indium	1.27E-04	760	0.10	--	--	--	--	--	--	0.10
Iodine	2.12E-06	760	0.0016	--	--	--	--	--	--	0.0016
Isopropanol	9.20E-03	760	6.99	--	--	--	--	--	--	6.99
Molybdenum	2.24E-07	760	0.00017	4.88E-07	600	0.00029	8.83E-06	530	0.0047	0.0047
PAH	5.90E-10	760	4.48E-07	--	--	--	--	--	--	--
Silver	1.40E-06	760	0.0011	--	--	--	--	--	--	0.0011
Thallium	ND	--	--	--	--	--	--	--	--	--
Tin	3.65E-08	760	2.77E-05	3.3E-06	600	0.0020	8.83E-06	530	0.0047	0.0047
Tungsten	1.29E-08	760	9.80E-06	--	--	--	--	--	--	9.80E-06
Vanadium	1.41E-07	760	0.00011	--	--	--	--	--	--	0.00011
Yttrium	6.59E-08	760	5.01E-05	--	--	--	--	--	--	5.008E-05
Zirconium	4.12E-07	760	0.00031	--	--	--	--	--	--	0.00031

Note: ND = Non-detectable

Source: KBN, 1995.

Table 2-12. Maximum Annual Emissions of Florida Air Toxics for Osceola Power Cogeneration Facility (total all boilers)

Florida Air Toxic	Biomass Emission Factor (lb/MMBtu)	Activity Factor (E12 Btu/yr)	Annual Emissions (TPY)	No. 2 Fuel Oil Emission Factor (lb/MMBtu)	Activity Factor (E12 Btu/yr)	Annual Emissions (TPY)	Coal Emission Factor (lb/MMBtu)	Activity Factor (E12 Btu/yr)	Annual Emissions (TPY)	Annual Emissions (TPY)
		Normal Operations								
Acetone	3.8E-04	8.208	1.56	--	--	--	--	--	--	1.56 *
Ammonia	1.50E-02	8.208	61.56	--	--	--	--	--	--	61.56
Barium	5.20E-06	8.208	0.021	--	--	--	--	--	--	0.021
Benzo(a)anthracene	7.53E-07	8.208	0.0031	--	--	--	--	--	--	0.0031 *
Benzo(a)pyrene	3.53E-08	8.208	0.00014	--	--	--	--	--	--	0.00014 *
Bromine	4.59E-05	8.208	0.19	--	--	--	--	--	--	0.19
Chrysene	3.53E-05	8.208	0.14	--	--	--	--	--	--	0.14 *
Copper – Annual	8.02E-05	8.208	0.33	--	--	--	--	--	--	0.33 *
Indium	1.27E-04	8.208	0.52	--	--	--	--	--	--	0.52 *
Iodine	2.12E-06	8.208	0.0087	--	--	--	--	--	--	0.0087 *
Isopropanol	9.20E-03	8.208	37.76	--	--	--	--	--	--	37.76 *
Molybdenum	2.24E-07	8.208	0.00092	--	--	--	--	--	--	0.00092
PAH	5.90E-10	8.208	2.42E-06	--	--	--	--	--	--	2.42E-06 *
Silver	1.40E-06	8.208	0.0057	--	--	--	--	--	--	0.0057 *
Thallium	ND	--	--	--	--	--	--	--	--	--
Tin	3.65E-08	8.208	0.00015	--	--	--	--	--	--	0.00015
Tungsten	1.29E-08	8.208	5.29E-05	--	--	--	--	--	--	5.29E-05 *
Vanadium	1.41E-07	8.208	0.00058	--	--	--	--	--	--	0.00058 *
Yttrium	6.59E-08	8.208	0.00027	--	--	--	--	--	--	0.00027 *
Zirconium	4.12E-07	8.208	0.0017	--	--	--	--	--	--	0.0017 *
		25% Oil Firing								
Acetone	3.8E-04	5.793	1.10	--	--	--	--	--	--	1.10
Ammonia	1.50E-02	5.793	43.45	1.50E-02	1.647	12.35	--	--	--	55.80
Barium	5.20E-06	5.793	0.015	6.69E-07	1.647	0.00055	--	--	--	0.016
Benzo(a)anthracene	7.53E-07	5.793	0.0022	--	--	--	--	--	--	0.0022
Benzo(a)pyrene	3.53E-08	5.793	0.00010	--	--	--	--	--	--	0.00010
Bromine	4.59E-05	5.793	0.13	6.97E-07	1.647	0.00057	--	--	--	0.13
Chrysene	3.53E-05	5.793	0.10	--	--	--	--	--	--	0.10
Copper – Annual	8.02E-05	5.793	0.23	--	--	--	--	--	--	0.23
Indium	1.27E-04	5.793	0.37	--	--	--	--	--	--	0.37
Iodine	2.12E-06	5.793	0.0061	--	--	--	--	--	--	0.0061
Isopropanol	9.20E-03	5.793	26.65	--	--	--	--	--	--	26.648
Molybdenum	2.24E-07	5.793	0.00065	4.88E-07	1.647	0.00040	--	--	--	0.0011
PAH	5.90E-10	5.793	1.71E-06	--	--	--	--	--	--	1.71E-06
Silver	1.40E-06	5.793	0.0041	--	--	--	--	--	--	0.0041
Thallium	ND	--	--	--	--	--	--	--	--	--

Table 2–12. Maximum Annual Emissions of Florida Air Toxics for Osceola Power Cogeneration Facility (total all boilers)

Florida Air Toxic	Biomass			No. 2 Fuel Oil			Coal			Annual Emissions (TPY)
	Emission Factor (lb/MMBtu)	Activity Factor (E12 Btu/yr)	Annual Emissions (TPY)	Emission Factor (lb/MMBtu)	Activity Factor (E12 Btu/yr)	Annual Emissions (TPY)	Emission Factor (lb/MMBtu)	Activity Factor (E12 Btu/yr)	Annual Emissions (TPY)	
Tin	3.65E–08	5.793	0.00011	3.3E–06	1.647	0.0027	––	––	––	0.0028 *
Tungsten	1.29E–08	5.793	3.74E–05	––	––	––	––	––	––	3.74E–05
Vanadium	1.41E–07	5.793	0.00041	––	––	––	––	––	––	0.00041
Yttrium	6.59E–08	5.793	0.00019	––	––	––	––	––	––	0.00019
Zirconium	4.12E–07	5.793	0.0012	––	––	––	––	––	––	0.0012
Yttrium	6.59E–08	5.793	0.00019	––	––	––	––	––	––	0.00019
Zirconium	4.12E–07	5.793	0.0012	––	––	––	––	––	––	0.0012
		5.4 % Coal Firing								
Acetone	3.8E–04	7.661	1.46	––	––	––	––	––	––	1.46
Ammonia	1.50E–02	7.661	57.46	––	––	––	0.048	0.482	11.57	69.03 *
Barium	5.20E–06	7.661	0.020	––	––	––	7.44E–05	0.482	0.018	0.038 *
Benzo(a)anthracene	7.53E–07	7.661	0.0029	––	––	––	––	––	––	0.0029
Benzo(a)pyrene	3.53E–08	7.661	0.00014	––	––	––	––	––	––	0.00014
Bromine	4.59E–05	7.661	0.18	––	––	––	7.90E–05	0.482	0.019	0.19 *
Chrysene	3.53E–05	7.661	0.14	––	––	––	––	––	––	0.14
Copper – Annual	8.02E–05	7.661	0.31	––	––	––	––	––	––	0.31
Indium	1.27E–04	7.661	0.49	––	––	––	––	––	––	0.49
Iodine	2.12E–06	7.661	0.0081	––	––	––	––	––	––	0.0081
Isopropanol	9.20E–03	7.661	35.24	––	––	––	––	––	––	35.241
Molybdenum	2.24E–07	7.661	0.00086	––	––	––	8.83E–06	0.482	0.0021	0.0030 *
PAH	5.90E–10	7.661	2.26E–06	––	––	––	––	––	––	2.26E–06
Silver	1.40E–06	7.661	0.0054	––	––	––	––	––	––	0.0054
Thallium	ND	––	––	––	––	––	––	––	––	––
Tin	3.65E–08	7.661	0.00014	––	––	––	8.83E–06	0.482	0.0021	0.0023
Tungsten	1.29E–08	7.661	4.94E–05	––	––	––	––	––	––	4.94E–05
Vanadium	1.41E–07	7.661	0.00054	––	––	––	––	––	––	0.00054
Yttrium	6.59E–08	7.661	0.00025	––	––	––	––	––	––	0.00025
Zirconium	4.12E–07	7.661	0.0016	––	––	––	––	––	––	0.0016
Yttrium	6.59E–08	7.661	0.00025	––	––	––	––	––	––	0.00025 *
Zirconium	4.12E–07	7.661	0.0016	––	––	––	––	––	––	0.0016

a Denotes maximum annual emissions for any fuel scenario.

Note: ND = Non–detectable

To minimize the potential for treated wood to be present in the wood waste stream, Osceola Power will not use any delivered wood fuel that contains an amount of treated or painted wood which would cause the wood waste to contain more than 56.7 ppm arsenic, 67.3 ppm chromium, or 53.2 ppm copper based upon a composite sample of the fuel. These concentrations are based upon a treated wood content of 2.4 percent. The derivation of these concentrations is based upon the concentrations of these substances present in both clean wood waste and treated wood (refer to Table 2-9).

The emission factors for arsenic, chromium and copper based upon 2.4 percent treated wood burning are presented in Table 2-10. To estimate maximum short-term emissions, it is assumed that 100 percent wood waste is being fired, with 2.4 percent treated wood. To estimate maximum annual emission factors, it is assumed that 50 percent of the biomass fuel is wood waste, although wood waste is expected to amount to only 33 percent of the biomass fuel on an annual basis.

2.5 FUGITIVE EMISSIONS OF PARTICULATE MATTER

Sources of fugitive particulate emissions were identified based on the descriptions of the biomass, coal and ash handling and storage processes as presented in previous sections. Emissions of fugitive dust can occur from four types of material handling operations: batch or continuous drop, crushing, wind erosion, and vehicular traffic. An emission inventory, identifying activities, uncontrolled emission factors, controls, activity factors, and annual fugitive dust emissions is presented in Table 2-13. These are in general the same factors and controls presented in the original application for the Osceola Power facility. Supportive information concerning wind erosion and vehicular traffic are presented in Appendix C.

For the biomass handling system the worst case flow of fuel was assumed, i.e., all of the biomass burned at the facility being delivered by truck. In reality, during the sugar processing season, the biomass fuel will be primarily bagasse from the sugar mill. The bagasse will be delivered directly to the boilers, bypassing the handling system (except for a small overfeed amount). Although many of the transfer points will be enclosed, in general no credit was taken for such control.

Also included in Table 2-13 are the dust collector baghouse at the boiler house, the ash silo bin vent filter, and the carbon silo bin vent filter. These sources will emit particulate matter.

Table 2-13. Osceola Power Facility Maximum Annual Fugitive Dust Emissions

SOURCE	TYPE OF OPERATION	M MOISTURE CONTENT (%)	U WIND SPEED (MPH)	UNCONTROLLED EMISSION FACTOR (LB/TON) a	CONTROL	CONTROL EFFICIENCY (%)	CONTROLLED EMISSION FACTOR (LB/TON)	ACTIVITY FACTOR	MAXIMUM ANNUAL PM(TSP) EMISSIONS (TONS/YR)	PM10 SIZE MULT.	MAXIMUM ANNUAL PM10 EMISSIONS (TONS/YR)
<u>Coal Handling</u>											
RAILCAR UNLOADING	BATCH DROP	4.5	9.4	0.00234	ENCLOSURE	70	0.00070	18,221 TPY	0.008	0.35	0.002
CONVEYOR-TO-COAL PILE	CONTINUOUS DROP	4.5	9.4	0.00234	NONE	0	0.00234	18,221 TPY	0.021	0.35	0.007
UNDERPILE RECLAIM HOPPER	CONTINUOUS DROP	4.5	9.4	0.00234	ENCLOSURE	90	0.00023	18,221 TPY	0.002	0.35	0.001
CONVEYOR-TO-CRUSHER	CONTINUOUS DROP	4.5	9.4	0.00234	ENCLOSURE	0	0.00234	18,221 TPY	0.021	0.35	0.007
COAL CRUSHER	COAL CRUSHING	--	--	0.02 h	ENCLOSURE	70	0.00600	18,221 TPY	0.055	0.45	0.025
CRUSHER-TO-CONVEYOR	CONTINUOUS DROP	4.5	9.4	0.00234	ENCLOSURE	0	0.00234	18,221 TPY	0.021	0.35	0.007
CONVEYOR-TO-BOILER SILO	CONTINUOUS DROP	4.5	9.4	0.00234	ENCLOSURE	0	0.00234	18,221 TPY	0.021	0.35	0.007
STORAGE PILE	WIND EROSION	--	--	--	NONE	0	--	--	0.211 e	0.5	0.105 e
COAL STORAGE PILE MAINTENANCE	VEHICULAR TRAFFIC	--	--	0.96 b	WATERING	50	0.48 lb/VMT	4,800 VMT c	1.157 e	0.35	0.405 e
<u>Biomass Handling</u>											
TRUCK DUMPS (2)	BATCH DROP	37	9.4	0.00012	NONE	0	0.00012	965,647 TPY	0.059	0.35	0.021
CHAIN CONVEYORS-TO-UNLOADING CONVEYOR (2)	CONTINUOUS DROP	37	9.4	0.00012	ENCLOSURE	0	0.00012	965,647 TPY	0.059	0.35	0.021
UNLOADING CONVEYOR-TO-SCREEN	CONTINUOUS DROP	37	9.4	0.00012	ENCLOSURE	0	0.00012	965,647 TPY	0.059	0.35	0.021
SCREEN	CONTINUOUS DROP	37	9.4	0.00012	NONE	0	0.00012	965,647 TPY	0.059	0.35	0.021
SCREEN-TO-HOGGER	CONTINUOUS DROP	37	9.4	0.00012	ENCLOSURE	0	0.00012	965,647 TPY	0.059	0.35	0.021
HOGGER	CRUSHING	--	--	0.02	ENCLOSED	95	0.00100	965,647 TPY	0.483	0.35	0.169
HOGGER-TO-STORAGE CONVEYOR	BATCH DROP	37	9.4	0.00012	ENCLOSURE	0	0.00012	965,647 TPY	0.059	0.35	0.021
SCREEN-TO-STORAGE CONVEYOR	CONTINUOUS DROP	37	9.4	0.00012	ENCLOSURE	0	0.00012	0 TPY	0.000	0.35	0.000
SCREEN-TO-BOILER FEED CONVEYOR	CONTINUOUS DROP	37	9.4	0.00012	ENCLOSURE	0	0.00012	0 TPY	0.000	0.35	0.000
STORAGE CONVEYOR-TO-RADIAL STACKER	CONTINUOUS DROP	37	9.4	0.00012	ENCLOSURE	0	0.00012	965,647 TPY	0.059	0.35	0.021
RADIAL STACKER-TO-BIOMASS STORAGE PILE	CONTINUOUS DROP	37	9.4	0.00012	NONE	0	0.00012	965,647 TPY	0.059	0.35	0.021
UNDERPILE RECLAIMERS (2)	CONTINUOUS DROP	37	9.4	0.00012	ENCLOSED	90	0.00001	965,647 TPY	0.006	0.35	0.002
RECLAIMERS-TO-BOILER FEED CONVEYOR (2)	CONTINUOUS DROP	37	9.4	0.00012	ENCLOSURE	0	0.00012	965,647 TPY	0.059	0.35	0.021
BOILER FEED CONVEYOR-TO-CHAIN DIST. CONVEYOR (2)	CONTINUOUS DROP	37	9.4	0.00012	ENCLOSURE	0	0.00012	965,647 TPY	0.059	0.35	0.021
CHAIN DIST. CONVEYOR -TO-BOILER METER BINS (4)	BATCH DROP	37	9.4	0.00012	ENCLOSURE	0	0.00012	965,647 TPY	0.059	0.35	0.021
BAGASSE CONVEYOR-TO-CHAIN DIST CONVEYOR (2)	CONTINUOUS DROP	37	9.4	0.00012	ENCLOSURE	0	0.00012	0 TPY	0.000	0.35	0.000
BAGASSE CONVEYOR-TO-RECYCLE CONVEYOR	CONTINUOUS DROP	37	9.4	0.00012	ENCLOSURE	0	0.00012	0 TPY	0.000	0.35	0.000
CHAIN DIST. CONVEYORS-TO-RECYLE CONVEYOR (2)	CONTINUOUS DROP	37	9.4	0.00012	ENCLOSURE	0	0.00012	96,565 TPY g	0.006	0.35	0.002
RECYCLE CONVEYOR-TO-RECYCLE STACKER	CONTINUOUS DROP	37	9.4	0.00012	ENCLOSURE	0	0.00012	0 TPY	0.000	0.35	0.000
RECYCLE CONVEYOR-TO-STORAGE CONVEYOR	CONTINUOUS DROP	37	9.4	0.00012	ENCLOSURE	0	0.00012	96,565 TPY g	0.006	0.35	0.002
RECYCLE STACKER-TO-BIOMASS STORAGE PILE	CONTINUOUS DROP	37	9.4	0.00012	NONE	0	0.00012	0 TPY	0.000	0.35	0.000
BIOMASS STORAGE PILES (2)	WIND EROSION	--	--	--	NONE	0	--	--	0.175 e	0.5	0.087 e
BIOMASS STORAGE PILE MAINTENANCE	VEHICULAR TRAFFIC	--	--	0.96 b	WATERING	50	0.48 lb/VMT	21,900 VMT d	5.278 e	0.35	1.647 e
BOILER HOUSE DUST COLLECTOR BAGHOUSE	--	--	--	--	BAGHOUSE	99	0.01 gr/acf	30,000 acfm	11.263	1.0	11.263
<u>Mercury Control System</u>											
CARBON SILO FILTER	--	--	--	--	BAGHOUSE	99	0.01 gr/acf	2,500 acfm	0.939	1.0	0.939
<u>Fly Ash Handling</u>											
FLY ASH SILO FILTER	--	--	--	--	BAGHOUSE	99	0.01 gr/acf	2,500 acfm	0.939	1.0	0.939
FLY ASH TRANSFER-TO-TRUCK	CONTINUOUS DROP	5.0	9.4	0.00202	WETTING	50	0.00101	31,954 TPY f	0.016	0.35	0.006
TOTAL									21.088		15.863

Notes/References

a Batch Drop and Continuous Drop Emission Factors are computed from AP-42 (USEPA, 1988) Section 11.2.3:
E = 0.0032 x (U/5) ^ 1.3 / (M/2) ^ 1.4 lb/ton
b Pound per Vehicle Mile Travel (lb/VMT), see Appendix C for derivation.
c Based on vehicle operating 8 hrs/day, 120 days/yr @ 5 mph.
d Based on vehicle operating 12 hrs/day, 365 days/yr @ 5 mph.
e Refer to Appendix C for derivation.
f Based on 965,647 TPY biomass @ 3.24% ash and 18,221 TPY coal @ 3.66% ash.
g Assuming 10% of biomass is overfeed and is returned to biomass storage pile..
h Emission Factor for Coal Crusher derived from AP-42 Table 8.23-1, for high moisture ore; same factor used for biomass crushing.

2.6 DISTILLATE FUEL STORAGE TANK EMISSIONS

Annual throughput amounts for the storage tank were developed based on the maximum annual No. 2 fuel oil usage for the boilers of 14 million gal/yr (refer to Table 2-2). Physical tank parameters, maximum throughput amounts, and estimated storage tank emissions are presented in Appendix D. VOC emissions were estimated using the TANKS (Version 2.0) computer program. This program was developed by the American Petroleum Institute (API) and uses equations from EPA's Compilation of Air Pollutant Emission Factors (AP-42), Section 12, to estimate breathing and working losses from fixed cone roof storage tanks. Printed output from the TANKS program is provided in Attachment D. As presented, estimated VOC emissions are 0.069 TPY from the storage tank.

2.7 COMPLIANCE DEMONSTRATION

Osceola Power will demonstrate compliance with the maximum heat input limits for the facility by monitoring fuel input rates and fuel characteristics on a periodic basis. In addition, steam production parameters (i.e., steam quantity, pressure, and temperature) and feedwater parameters will be continuously monitored to allow calculation of heat input by use of an assumed heat transfer efficiency for each fuel.

Continuous stack gas monitoring for opacity, NO_x, SO_2, CO, and oxygen will be installed on each boiler flue gas stream. The oxygen monitor will be used with automatic feedback or manual controls to continuously maintain the air/fuel ratio at an optimum.

In addition, per the zoning conditions recommended by Palm Beach County and agreed to by Osceola Power, stack testing will be performed for PM, NO_x, CO, SO_2, lead, mercury and VOC every 6 months during the first 2 years of operation. If these tests show compliance with the permitted emission limits, the stack testing frequency will be reduced to that typically required by FDEP (i.e., once every year or once every 5 years, depending upon pollutant).

The heat input to the boilers will be measured in two separate ways. The first method is by continuously monitoring steam production, pressure and temperature and using the design heat transfer efficiencies (refer to Table 2-2). Using this information and the enthalpies of the steam, the heat input can be calculated. The second method will consist of the continuous measurement of the fuel input to each boiler. Conveyor belts supplying fuel to the boilers will be fitted with belt scales which will measure the weight of biomass and coal and provide an integrated hourly total. Separate metering devices will be provided for coal so that the heat input due to coal can be determined even when burning a combination of coal and biomass fuels. Utilizing fuel quality data (i.e., heating value), the heat input to each boiler can be calculated.

Fuel quality measurements will be made on all fuels in order to provide information for heat input and emission calculations. Biomass fuels (bagasse and wood waste) are very low in sulfur content, and the heating value of these fuels are well established. Therefore, a rigorous sampling program is not necessary. It is proposed to collect daily biomass samples at a location along the conveying system, prior to the boiler, whenever biomass fuels are fired during a day. These daily samples will be composited into one weekly sample each calendar week. This composite sample will be analyzed for sulfur, moisture, ash and heating value. These data will be used to calculate heat input and SO_2 emissions due to biomass fuels. This sampling program is proposed to be conducted for 1-year duration in order to develop a database for biomass fuels. After the initial 1-year period, the sampling frequency will be reduced to a reasonable level agreeable to FDEP. Osceola Power will present the data to FDEP in order to justify the reduced sampling frequency.

For coal, each coal shipment, which will typically consist of a 50 to 60 car unit train, will be accompanied by a coal analysis representative of the shipment. The analysis will include heating value and sulfur content.

Osceola Power has determined that the most accurate, cost-effective method to determine SO_2 emissions from the facility is to install a continuous SO_2 emission monitor (that meets EPA reference method specifications). This will allow the direct determination of hourly SO_2 emissions on a continuous basis, for determining compliance with the hourly, 24-hour average, and annual average emission limits for the facility.

Osceola Power will design and implement a management and testing program for the wood waste and other materials delivered to the facility for fuel. The program will be designed to keep painted and chemically treated wood, household garbage, toxic or hazardous non-biomass and non-combustible waste material from being burned at the plant. This program will be submitted to the FDEP's Bureau of Air Regulation for review and approval at least 60 days before the commencement of operations of the cogeneration facility. At a minimum, the program will provide for the routine inspection and/or testing of the fuel at the originating wood yard sites as well as at the cogeneration site, to ensure that the quantities of painted or chemically treated wood in the fuel are minimized. Osceola Power will perform a daily visual inspection of any wood waste or similar vegetative matter that has been delivered to the facility for use as fuel. Any shipment observed to contain prohibited materials will not be accepted unless such materials can be readily segregated and removed from the wood waste and vegetative matter. Osceola Power will not use any delivered fuel that contains an amount of treated or painted wood which would cause the wood waste to contain more than 56.7 parts per million (ppm) arsenic, 67.3 ppm chromium, or 53.2 ppm copper based on analysis of a composite sample of the fuel.

3.0 AIR QUALITY REVIEW REQUIREMENTS AND SOURCE APPLICABILITY

Osceola Power received a state and federal PSD construction permit in 1993. PSD review was triggered for SO_2, beryllium, and fluorides. The facility is now under construction, and has not yet started operations. Osceola Power is now proposing changes to the facility and desires to amend the PSD construction permit. A comparison of the original baseline, current permit limits, and the proposed revised cogeneration facility emissions is presented in Table 3-1.

For the pollutants SO_2, lead, beryllium, and fluorides, no increase over the current permitted annual emissions is being requested. As a result, PSD review will not be triggered, and no permit amendment is required for the annual emissions of these pollutants.

For other pollutants, a relaxation in the current federally enforceable restrictions on emission rates is being requested. PSD review was not previously triggered for these pollutants. In such cases, PSD rules required that the modification be evaluated for PSD applicability as if construction of the facility had not yet commenced. In other words, the proposed revised emission rates are to be compared with the original PSD baseline emissions to determine if PSD review is triggered [F.A.C. Rule 62-212.400(2)(g)]. This comparison is presented in Table 3-1. The original PSD baseline emissions, the proposed cogeneration emissions, and the net change in emissions are shown. Also shown are the PSD significant emission rates. As shown, PSD review is not triggered for any pollutants.

Although PSD review is not being triggered by the proposed modification, changes are occurring in short-term emission rates. As a result, the previous modeling analysis has been updated. This analysis is presented in Section 4.0.

Table 3-1. PSD Source Applicability Analysis for Osceola Power Limited Partnership Facility

Regulated Pollutant	Original PSD Baseline Emissions (TPY)	Cogeneration Facility Annual Emissions (TPY)	Net Change (TPY)	Significant Emission Rate (TPY)	Current Permit Limit (TPY)	PSD Applies?	Permit Amendment Required?
Particulate (TSP)	357.7	144.2[a]	-213.5	25	114.7	No	Yes
Particulate (PM10)	321.9	139.0[b]	-182.9	15	108.5	No	Yes
Sulfur dioxide	178.5	339.0	160.5	40	353.2	No	No
Nitrogen oxides	437.8	477.1	39.3	40	424.9	No	Yes
Carbon monoxide	5,992.3	1,436.4	-4,555.9	100	1,225.0	No	Yes
Volatile org. compds.	208.6	219.2	10.6	40	210.0	No[c]	Yes
Lead	0.16	0.011	-0.15	0.6	0.10	No	No
Mercury	0.0158[d]	0.0168	0.0010	0.1	0.0161	No	Yes
Beryllium	0.00002	0.0013	0.00128	0.0004	0.0014	No	No
Fluorides	0.0079	5.25	5.24	3	5.8	No	No
Sulfuric acid mist	5.36	6.00	0.64	7	5.2	No	Yes
Total reduced sulfur	—	—	0	10	—	No	No
Asbestos	—	—	0	0.007	—	No	No
Vinyl Chloride	—	—	0	0	—	No	No

[a] Includes 123.1 TPY from boilers and 21.1 TPY from fugitive dust emission sources.

[b] Includes 123.1 TPY from boilers and 15.9 TPY from fugitive dust emission sources.

[c] Nonattainment review does not apply since the increase in VOC emissions is less than 40 TPY.

4.0 AIR QUALITY IMPACT ANALYSIS

4.1 GENERAL MODELING APPROACH

An air quality analysis for the Osceola Power cogeneration facility was conducted for SO_2. Although the proposed modification is not subject to PSD review, analysis is being performed to demonstrate compliance with Florida AAQS and, since the Osceola Power cogeneration facility is an increment consuming facility, to demonstrate compliance with the allowable EPA/FDEP PSD Class I and Class II increments for SO_2. In addition, an impact analysis for all emitted Florida Air Toxics (FATs) pollutants was performed for comparison to FDEP's air reference concentrations (ARCs).

The general modeling approach followed EPA and FDEP modeling guidelines for determining compliance with AAQS and PSD increments. For this compliance analysis, a significant impact analysis was performed to determine the distance to which the proposed modification will be in excess of the EPA/FDEP significant impact levels. If the project's impacts are above the significant impact levels, a more detailed modeling analysis is performed. As is FDEP policy, the highest annual average and highest short-term (i.e., 24 hours or less) concentrations are to be compared to the applicable significant impact levels. If the screening analysis indicates that maximum predicted concentrations are above 75 percent of the significant impact levels, modeling refinements are performed.

The proposed facility is located in the area of numerous sugar mills, which operate their boilers only part of the year. For modeling purposes, it was necessary to account for the partial year operation of the sugar mill boilers by utilizing two emission inventories, a crop-season inventory and an off-season inventory. The maximum crop season period was assumed to extend from October 1 through April 30. The maximum off-season period was assumed to extend from March 1 through October 31. Since the beginning and ending dates of the crop season vary from year to year, the two seasons were defined such that they overlap several months of the year.

The crop-season inventory included the sugar mill boiler emissions (and/or offsets for PSD purposes, if the boilers were to be shut down). The off-season inventory excluded the emissions and offsets from the sugar mill sources. The two emission inventories are identical in regards to all non-sugar-mill sources. For cases where the maximum impacts were well below the applicable standards, the analysis was simplified by conservatively assuming that the sugar mill sources operate year round.

4.2 MODEL SELECTION

4.2.1 AAQS/PSD CLASS II

The selection of an appropriate air dispersion model was based on the model's ability to simulate impacts in areas surrounding the Osceola Power site. Within 50 km of the site, the terrain can be described as simple, i.e., flat to gently rolling. As defined in EPA modeling guidelines, simple terrain is considered to be an area where the terrain features are all lower in elevation than the top of the stack(s) under evaluation. Therefore, a simple terrain model was selected to predict maximum ground-level concentrations.

The Industrial Source Complex Short-term (ISCST2, Version 93109) dispersion model (EPA, 1992b) was used to evaluate the pollutant emissions from the proposed facility and other existing major facilities. This model is provided by EPA through its Technology Transfer Network (TTN) Bulletin Board Service (BBS). The ISCST2 model is applicable to sources located in either flat or rolling terrain where terrain heights do not exceed stack heights. The ISCST2 model is designed to calculate hourly concentrations based on hourly meteorological parameters (i.e., wind direction, wind speed, atmospheric stability, ambient temperature, and mixing heights). The hourly concentrations are processed into non-overlapping, short-term and annual averaging periods. For example, a 24-hour average concentration is based on 24 1-hour averages calculated from midnight to midnight of each day. For each short-term averaging period selected, the highest and second-highest average concentrations are calculated for each receptor. As an option, a table of the 50 highest concentrations over the entire field of receptors can be produced.

Major features of the ISCST2 model are presented in Table 4-1. The ISCST2 model has both rural and urban mode options which affect the wind speed profile exponent law, dispersion rates, and mixing-height formulations used in calculating ground level concentrations. The criteria used to determine when the rural or urban mode is appropriate are based on land use near the source's surroundings (Auer, 1978). If the land use is classified as heavy industrial, light-moderate industrial, commercial, or compact residential for more than 50 percent of the area within a 3-km radius circle centered on the proposed source, the urban option should be selected. Otherwise, the rural option is more appropriate.

Table 4-1. Major Features of the ISCST2 Model

- Polar or Cartesian coordinate systems for receptor locations
- Rural or one of three urban options that affect wind speed profile exponent, dispersion rates, and mixing height calculations
- Plume rise as a result of momentum and buoyancy as a function of downwind distance for stack emissions (Briggs, 1969, 1971, 1972, and 1975)
- Procedures suggested by Huber and Snyder (1976); Huber (1977); Schulmann and Hanna (1986); and Schulmann and Scire (1980) for evaluating building wake effects
- Direction-specific building heights and projected widths for all sources for which downwash is considered.
- Procedures suggested by Briggs (1974) for evaluating stack-tip downwash
- Separation of multiple-point sources
- Consideration of the effects of gravitational settling and dry deposition on ambient particulate concentrations
- Capability of simulating point, line, volume, and area sources
- Capability to calculate dry deposition
- Variation of wind speed with height (wind speed-profile exponent law)
- Concentration estimates for 1-hour to annual average
- Terrain-adjustment procedures for elevated terrain, including a terrain truncation algorithm
- Receptors located above local terrain (i.e., "flagpole" receptors)
- Consideration of time-dependent exponential decay of pollutants
- The method of Pasquill (1976) to account for buoyancy-induced dispersion
- A regulatory default option to set various model options and parameters to EPA recommended values (see text for regulatory options used)
- Procedure for calm-wind processing
- Wind speeds less than 1 m/s are set to 1 m/s.

Source: EPA, 1992b.

In this analysis, the EPA regulatory default options were used to predict all maximum impacts. The regulatory default options include:

1. Final plume rise at all receptor locations,
2. Stack-tip downwash,
3. Buoyancy-induced dispersion,
4. Default wind speed profile coefficients for rural or urban option,
5. Default vertical potential temperature gradients,
6. Calm wind processing, and
7. Reducing calculated SO_2 concentrations in urban areas by using a decay half-life of 4 hours.

4.2.2 PSD CLASS I

For the PSD Class I analysis, the ISCST2 model was used initially as a screening model for estimating impacts on the Everglades National Park (ENP) Class I area. EPA and FDEP recommend this model as a screening tool for receptors located more than 50 km from a source. For a more refined impact assessment on the ENP, the MESOPUFF II model was utilized. This model is more appropriate for long-range transport applications, where receptors are located more than 50 km from a source.

4.3 MODELING ANALYSIS

4.3.1 SIGNIFICANT IMPACT ANALYSIS

The significant impact area for SO_2 was determined based on the Osceola Power facility emissions only (i.e., no credit was taken for shutdown of the existing Osceola boilers). Emission and stack parameters for the proposed cogeneration facility are presented in Table 4-2.

4.3.2 AAQS/PSD MODELING ANALYSIS

In general, when 5 years of meteorological data are used, the highest annual and the highest, second-highest (HSH) short-term concentrations are to be compared to the applicable AAQS and allowable PSD increments. The HSH concentration is calculated for a receptor field by:

1. Eliminating the highest concentration predicted at each receptor,
2. Identifying the second-highest concentration at each receptor, and
3. Selecting the highest concentration among these second-highest concentrations.

Table 4-2. Summary of Osceola Power Emission, Stack, and Operating Data Used in the Modeling Analysis

		Coordinates Relative to Sol-Energy Boiler Stacks (m)		Stack Data (m)		Operating Data		
ISCST2 Source Identification	Source Description	X	Y	Height	Diameter	Temperature (K)	Velocity (m/sec)	Modeled SO_2 Emissions (g/sec)
PSD Baseline								
OSBLR1B	Boiler 1	166	-65	22.0	1.52	342	8.98	-5.07
OSBLR2B	Boiler 2	164	-50	22.0	1.52	342	14.22	-16.32
OSBLR3B	Boiler 3	165	-36	22.0	1.93	342	11.23	-7.26
OSBLR4B	Boiler 4	153	-23	22.0	1.83	342	13.35	-13.61
Proposed								
OSCOCRN	Osceola Power Boilers 1 & 2[a]	0	0	60.96	2.44	419.3	21.34	160.27

Note:
g/sec = grams per second.
K = Kelvin.
lb/MMBtu = pounds per million British thermal units.
m = meters.
m/sec = meters per second.
SO_2 = sulfur dioxide.

[a] Stack parameters based on coal firing.

This approach is consistent with air quality standards and allowable PSD increments, which permit a short-term average concentration to be exceeded once per year at each receptor. To develop the maximum short-term concentrations for the proposed project, the modeling approach was divided into screening and refined phases to reduce the computation time required to perform the modeling analysis. For this study, the only difference between the two phases is the density of the receptor grid spacing employed when predicting concentrations. Concentrations are predicted for the screening phase using a coarse receptor grid and a 5-year meteorological data record.

Refinements of the maximum predicted concentrations are typically performed for the receptors of the screening receptor grid at which the highest and/or HSH concentrations occurred over the 5-year period. Generally, if the maximum concentration from other years in the screening analysis are within 10 percent of the overall maximum concentration, those other concentrations are refined as well. Typically, if the highest and HSH concentrations are in different locations, concentrations in both areas are refined.

Modeling refinements are performed for short-term averaging times by using a denser receptor grid, centered on the screening receptor to be refined. The angular spacing between radials is 2 degrees and the radial distance interval between receptors is 100 m. Annual modeling refinements are developed similarly. If the maximum screening concentration is located on the plant property boundary, additional plant boundary receptors are input, spaced at a 2-degree angular interval and centered on the screening receptor. The domain of the refinement grid extends to all adjacent screening receptors.

The air dispersion model is executed with the refined grid for the entire year of meteorology during which the screening concentration occurred. This approach is used to ensure that a valid HSH concentration is obtained. A more detailed description of the emission inventory, meteorological data, and screening receptor grids used in the analysis, is presented in the following sections.

A complete description of the modeling approach used for application of the MESOPUFF II model is contained in Appendix E.

4.4 METEOROLOGICAL DATA

Meteorological data used in the ISCST2 model to determine air quality impacts consisted of a concurrent 5-year period of hourly surface weather observations and twice-daily upper air soundings from the National Weather Service (NWS) stations at West Palm Beach. The 5-year period of meteorological data was from 1982 through 1986. The NWS station at West Palm Beach, located approximately 60 km east of the Osceola Power site, was selected for use in the study because it is the closest primary weather station to the study area and is most representative of the plant site. The surface observations included wind direction, wind speed, temperature, cloud cover, and cloud ceiling.

The wind speed, cloud cover, and cloud ceiling values were used in the ISCST meteorological preprocessor program to determine atmospheric stability using the Turner stability scheme. Based on the temperature measurements at morning and afternoon, mixing heights were calculated with the radiosonde data using the Holzworth approach (1972). Hourly mixing heights were derived from the morning and afternoon mixing heights using the interpolation method developed by EPA (Holzworth, 1972). The hourly surface data and mixing heights were used to develop a sequential series of hourly meteorological data (i.e., wind direction, wind speed, temperature, stability, and mixing heights). Because the observed hourly wind directions were classified into one of thirty-six 10-degree sectors, the wind directions were randomized within each sector to account for the expected variability in air flow. These calculations were performed by using the EPA RAMMET meteorological preprocessor program.

Meteorological data used in the MESOPUFF II modeling analysis are discussed in Appendix E.

4.5 EMISSION INVENTORY

4.5.1 OSCEOLA FARMS AND Osceola Power

Stack and operating parameters and emission rates for the Osceola Farms PSD baseline sources are presented in Table 4-2. Parameters for the proposed cogeneration facility are also shown. The current mill configuration is somewhat different than in the PSD baseline period (i.e., 1975). Boilers 5 and 6 have been added at the mill, Boiler No. 1 has been removed, and the other boilers have undergone stack height increases.

4.5.2 OTHER AIR EMISSION SOURCES

The Osceola Power cogeneration facility produces a significant impact for SO_2. Therefore, a detailed impact analysis has been performed for this pollutant. Osceola Power's SIA was determined to be 60 km. An inventory of all facilities used in the modeling analyses is presented in Table 4-3. This list was developed from the 1992 modeling analysis performed for the Osceola facility, supplemented by existing source permits and other recent modeling analyses performed in this area through the present date. This list includes all SO_2 sources located within 70 km of the Osceola Power site and emitting greater than 25 TPY. Also included are six sources located outside the SIA, but which may have a significant impact on the SIA or are PSD increment consuming sources. Beyond the SIA, sources emitting less than 100 TPY were not included in the analysis.

A summary of all source data used in the modeling analysis, including sources designated as PSD (increment consuming or expanding) sources, is presented in Table 4-4. Table 4-4 details which sources were used in the AAQS, PSD Class II, and PSD Class I modeling analyses. Included in this list is the Okeelanta Power cogeneration facility, which replaced the existing Okeelanta sugar mill. Therefore, the existing Okeelanta sources are included in the table as increment expanding sources. A review of sources in the inventories indicated several significant changes in this inventory through the present date notable for the Dade County RRF and U.S. Sugar mill in Clewiston. For the U.S. Sugar Corporation Bryant mill, maximum SO_2 emissions were calculated based on permit information and the sulfur content of fuels utilized.

Sources within one facility were sometimes combined if their stack heights were the same and the sources had similar operating parameters. Some small sources were sometimes combined with larger sources within the same facility (emissions were added to the larger source).

For most facilities, 3-hour worst-case emission rates were used for all averaging time analyses. For 24-hour and annual averaging times, 24-hour emission rates were used in place of 3-hour emission rates for a few sources, where available. These are noted in the footnote at the bottom of Table 4-4.

Table 4-3. Non-Osceola Sources (>25 TPY) Used in the Modeling Inventories

APIS Number	Facility	County	UTM Coordinates (km)		Location Relative To Proposed Site (km)		Distance From Proposed Site (km)	Direction From Proposed Site (degrees)	Maximum SO_2[a] Emissions (TPY)
			East	North	X	Y			
52FTM500061	U.S. Sugar -Bryant	Palm Beach	538.8	2968.1	-5.4	0.1	5.4	271	2,364
52FTM500026	Sugar Cane Growers	Palm Beach	534.9	2953.3	-9.3	-14.7	17.4	212	4,269
50PMB500021	Pratt & Whitney	Palm Beach	559.2	2978.3	15.0	10.3	18.2	56	3,386
50WPB430102	Bechtel Indiantown	Martin	545.6	2991.5	1.4	23.5	23.5	3	2,629
52FTM500016	Atlantic Sugar	Palm Beach	552.9	2945.2	8.7	-22.8	24.4	159	1,484
50PMB500086	Glades Correctional Institute	Palm Beach	523.4	2955.2	-20.8	-12.8	24.4	238	485
50WPB430001	FPL -Martin	Martin	543.1	2992.9	-1.1	24.9	24.9	357	93,788
50PMB500332	Okeelanta Power Boilers 1, 2 & 3	Palm Beach	525.0	2937.4	-19.2	-28.6	34.4	214	1,596
52FTM260001	Evercane Sugar	Hendry	509.6	2954.2	-34.6	-13.8	37.3	248	1,408
50WPB430007	Dickerson	Martin	569.5	2995.9	25.3	27.9	37.7	42	58
52FTM260003	US Sugar Clewiston	Hendry	506.1	2956.9	-38.1	-11.1	39.7	254	1,384
50WPB500234	Palm Beach Resource Recovery	Palm Beach	585.8	2960.2	41.6	-7.8	42.3	101	1,533
50WPB430021	Stuart Contracting	Martin	575.2	3006.8	31.0	38.8	49.7	39	100
50PMB500042	FPL -Riviera Beach	Palm Beach	594.2	2960.6	50.0	-7.4	50.5	98	77,815
50PMB500045	Lake Worth Utilities	Palm Beach	592.8	2943.7	48.6	-24.3	54.3	117	2,302
52FTM260015	Southern Gardens	Hendry	487.6	2957.6	-56.6	-10.4	57.5	260	173
50WPB560003	Fort Pierce Utilities	St. Lucie	566.8	3036.3	22.6	68.3	71.9	18	2,708
50WPB062120	North Broward Res. Rec.	Broward	583.6	2907.6	39.4	-60.4	72.1	147	896
30ORL310029	Vero Beach Power	St. Lucie	567.1	3056.5	22.9	88.5	91.4	15	18,496
50WPB062119	South Broward Res. Rec.	Broward	579.6	2883.3	35.4	-84.7	91.8	157	1,318
50BRO060037	FPL -Fort Lauderdale	Broward	580.1	2883.3	35.9	-84.7	92.0	157	65,964
50BRO060036	FPL -Port Everglades	Broward	587.4	2885.3	43.2	-82.7	93.3	152	76,239

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[a] Indicates facilities with sources that only operate part of the year; October 1 through April 30.
PSD indicates facilities with PSD increment consuming and/or expanding sources.

Table 4-4. Summary of Non-Osceola Source Data Used in Modeling Analysis (Page 1 of 3)

		Stack							Modeled in		
APIS Number	Facility	Height (m)	Diameter (m)	Temp (K)	Velocity (m/s)	SO_2 3-Hour Emission Rate (g/s)	SO_2 24-Hour Emission Rate (g/s)	PSD Source? (EXP/CON)	AAQS	Class II	Class I
52FTM500016	Atlantic Sugar										
	Unit 1[a]	18.9	1.92	346	12.7	17.24	17.24		Yes	No	No
	Unit 2[a]	18.9	1.92	342	10.9	22.50	22.50		Yes	No	No
	Unit 3[a]	21.9	1.83	341	17.5	16.88	16.88		Yes	No	No
	Unit 4[a]	18.3	1.83	344	15	16.88	16.88		Yes	No	No
	Unit 5[a] PSD	27.4	1.68	339	15.7	11.80	11.80	CON	Yes	Yes	Yes
50WPB430102	Bechtel Indiantown PSD	150.9	4.88	333.2	30.5	75.64	75.64	CON	Yes	Yes	Yes
50DAD130348	Dade County RRF PSD										
	Units 1&2 proposed mod.	76.2	3.66	405.4	15.86	26.41	12.32	CON	No	No	Yes
	Units 3&4 proposed mod.	76.2	3.66	405.4	15.86	26.41	12.32	CON	No	No	Yes
	Unit 5 proposed	76.2	2.97	399.8	15.74	18.43	8.61	CON	No	No	Yes
50WPB430007	Dickerson	12.8	1.83	321.9	9.75	1.69	1.69		Yes	No	No
52FTM260001	Evercane Sugar[a]	21.9	1.1	477	10.1	11.80	11.80		Yes	No	No
	Fort Pierce	45.7	4.88	411.0	10.97	77.9	77.9		Yes	No	No
50BRO060037	FPL - Lauderdale										
	CTs 1-4 PSD	45.7	4.88	411	10.97	271.10	271.10	CON	Yes	Yes	Yes
	4&5 PSD Baseline	46	4.27	422	14.63	-457.00	-457.00	EXP	No	Yes	Yes
50WPB430001	FPL Martin										
	Units 1&2	152.1	7.99	420.9	21.03	1743.79	1743.79		Yes	No	No
	Aux Blr PSD	18.3	1.1	535.4	15.24	12.90	12.90	CON	Yes	Yes	Yes
	Diesl Gens PSD	7.6	0.3	785.9	39.62	0.51	0.51	CON	Yes	Yes	Yes
	Units 3&4 PSD	64.9	6.1	410.9	18.9	470.40	470.40	CON	Yes	Yes	Yes
50BRO060036	FPL - Port Everglades										
	GT 1-2	15.5	5.49	733	21.34	488.39	488.39		Yes	No	No
	Units 1&2	104.9	4.27	416	18.59	637.54	637.54		Yes	No	No
	Units 3&4	104.5	5.52	108	19.2	1067.16	1067.16		Yes	No	No
50PMB500042	FPL - Riviera Beach										
	Unit 2	45.7	4.57	430.2	7.62	124.86	124.86		Yes	No	No
	3&4	90.8	4.88	408	18.9	846.33	846.33		Yes	No	No
50PMB500086	Glades Corr Institute	9.8	0.4	389	11.28	2.82	2.82		Yes	No	No
50PMB500045	Lake Worth										
	Units 1&2	18.23	1.52	434.1	6.19	72.58	72.58		Yes	No	No
	Units 3&4	38.1	2.29	408	9.69	237.90	237.90		Yes	No	No
	Unit 5	22.9	0.95	450.2	18.29	11.59	11.59		Yes	No	No
52FTM360119	Lee County RRF PSD	83.8	1.88	388.5	19.81	14.00	14.00	CON	No	No	Yes
50WPB062120	North Broward RRF PSD	58.5	3.96	381	18.01	35.40	35.40	CON	Yes	Yes	Yes

Table 4-4. Summary of Non-Osceola Source Data Used in Modeling Analysis (Page 2 of 3)

APIS Number	Facility	Stack Height (m)	Stack Diameter (m)	Temp (K)	Velocity (m/s)	SO_2 3-Hour Emission Rate (g/s)	SO_2 24-Hour Emission Rate (g/s)	PSD Source? (EXP/CON)	Modeled in AAQS	Modeled in Class II	Modeled in Class I
50PMB500332	Okeelanta										
	Boiler 4 PSD Baseline	22.9	2.29	333	7.36	-10.95	-10.95	EXP	No	No	Yes
	Boiler 5 PSD Baseline	22.9	2.29	333	12.07	-15.64	-15.64	EXP	No	No	Yes
	Boiler 6 PSD Baseline	22.9	2.29	334	8.74	-15.64	-15.64	EXP	No	No	Yes
	Boiler 10 PSD Baseline	22.9	2.29	334	10.35	-17.15	-17.15	EXP	No	No	Yes
	Boiler 11 PSD Baseline	22.9	2.29	342	9.89	-16.79	-16.79	EXP	No	No	Yes
	Boiler 12 PSD Baseline	22.9	2.29	330	8.16	-20.58	-20.58	EXP	No	No	Yes
	Boiler 14 PSD Baseline	22.9	2.29	333	8.28	-20.03	-20.03	EXP	No	No	Yes
	Boiler 15 PSD Baseline	22.9	2.29	332	10.23	-16.79	-16.79	EXP	No	No	Yes
	Okeelanta Boilers 1 and 2	60.66	2.44	450	21.25	222.26	222.26	CON	Yes	Yes	Yes
30ORL310029	City of Vero Beach										
	Fossil Fuel Steam Unit 1	60.96	1.83	451	6.4	65.8	65.8		Yes	No	No
	Fossil Fuel Steam Unit 2	60.96	1.71	451	25.3	84.4	84.4		Yes	No	No
	Fossil Fuel Steam Unit 3	60.96	2.13	485	10.4	144.5	144.5		Yes	No	No
	Fossil Fuel Steam Unit 4	60.96	2.13	463	15.5	69.0	69.0		Yes	No	No
50WPB500234	Palm Beach RRF 1&2 PSD	76.2	2.04	505.2	24.9	85.05	85.05	CON	Yes	Yes	No
50PMB500021	Pratt & Whitney										
	ACHR-1	1.8	0.91	500	40.23	16.02	16.02		Yes	No	No
	ACHR-2	15.2	0.91	500	40.23	47.92	47.92		Yes	No	No
	ACHR-3	4.6	3.38	700	13.44	23.46	23.46		Yes	No	No
	BO-12	4.6	0.76	500	6.92	9.08	9.08		Yes	No	No
	LI-1 MW	8.2	0.67	2000	8.35	6.18	6.18		Yes	No	No
50WPB062116	South Broward RRF PSD	59.4	3.96	381	18.01	37.91	37.91	CON	Yes	Yes	Yes
52FTM260015	Southern Gardens PSD	22	0.64	479.8	17.48	4.99	4.99	CON	Yes	Yes	Yes
	Stuart Contracting	11.9	1.22	421.9	24.08	1.99	1.99		Yes	No	No
52FTM500026	Sugar Cane Growers										
	Unit 3[a]	24.4	1.6	344	15.6	4.40	4.40		Yes	No	No
	Unit 4 PSD[a]	33.5	1.63	344	10.6	24.20	24.20	CON	Yes	Yes	Yes
	Unit 4 PSD Baseline[a]	25.9	2.82	344	10.6	-24.20	-24.20	EXP	No	Yes	Yes
	Unit 5[a]	24.4	1.4	344	15.2	16.20	16.20		Yes	No	No
	Unit 8 PSD[a]	47.2	3.05	344	10.6	26.70	26.70	CON	Yes	Yes	Yes
	Unit 1&2[a]	24.4	1.4	344	11.4	24.20	24.20		Yes	No	No
	Unit 6&7[a]	12.2	2.13	606	11.2	51.00	51.00		Yes	No	No
50DAD130020	Tarmac										
	Kiln 1	61	2.44	465	12.80	5.67	5.67		No	No	No
	Kiln 2 PSD Baseline	61	2.44	465	12.84	-5.71	-5.71	EXP	No	No	Yes
	Kiln 3 PSD Baseline	61	4.57	472	10.78	-2.76	-2.76	EXP	No	No	Yes
	Kiln 2 PSD	61	2.44	422	9.1	24.57	24.57	CON	No	No	Yes
	Kiln 3 PSD	61	4.57	450	11.04	51.43	51.43	CON	No	No	Yes

Table 4-4. Summary of Non-Osceola Source Data Used in Modeling Analysis (Page 3 of 3)

APIS Number	Facility	Stack Height (m)	Stack Diameter (m)	Temp (K)	Velocity (m/s)	SO_2 3-Hour Emission Rate (g/s)	SO_2 24-Hour Emission Rate (g/s)	PSD Source? (EXP/CON)	Modeled in AAQS	Modeled in Class II	Modeled in Class I
52FTM260003	US Sugar Clewiston										
	Unit 3[a]	27.4	2.29	340	14.54	28.16	22.99		Yes	No	No
	Unit 4 PSD[a]	45.7	2.51	334	19.66	16.26	14.78	CON	Yes	Yes	Yes
	Units 1&2[a]	22.9	1.86	339	35.54	95.22	80.68		Yes	No	No
	Units 5&6[a]	19.8	1.83	340	9.78	4.48	4.48	EXP	Yes	No	No
	Unit 7	68.6	2.63	340	21.7	15.75	15.75	CON	Yes	Yes	Yes
52FTM500061	US Sugar-Bryant										
	Unit 5 PSD[a]	42.7	2.9	345	11.49	68.07	67.38	CON	Yes	Yes	Yes
	Unit 1,2&3[a]	19.8	1.64	342	36.4	174.36	63.66		Yes	No	No

[a] These sources operate only during the crop season, October 1 through April 30.

Three separate modeling emission inventories were prepared for the modeling effort.

1. For the AAQS analysis, all sources listed in Table 4-4 and located within 70 km of the proposed site, and major utilities located within 100 km of the proposed site were used.
2. The Class II inventory included PSD increment consuming and/or expanding sources within 70 km and major utility PSD increment consuming and/or expanding sources within 100 km. To be conservative and to simplify the screening modeling analysis, increment expanding shutdowns of sugar mill boilers (i.e., at Okeelanta and Osceola Farms) were not modeled. In addition, increment consuming sugar mill boilers (i.e., at Atlantic Sugar, Sugar Cane Growers, and U.S. Sugar Clewiston and Bryant) were assumed to operate year around. However, for the 24-hour averaging time in the refined analysis, the modeling analysis was separated into the crop and off-season time periods, with the sugar mill sources reflected appropriately in the inventory.
3. An emission inventory for modeling SO_2 at the Everglades National Park, a PSD Class I area, was developed to include all PSD sources within 100 km from the Everglades National Park. The inventory included regional resource recovery facilities (e.g, Lee, Dade, and Broward counties), future expansion at FPL Martin power facility in Martin County, the Okeelanta Power cogeneration facility, and all increment-consuming sugar mill sources. Offsets from Okeelanta and Osceola were applied only during the crop season time period. The PSD Class I inventory was therefore subdivided into two inventories, crop-season and off-season. As discussed previously, two seasons were modeled with overlapping periods. No offsets were applied for the non-crop season. The two separate analyses were compared after screening results were complete. Highest impacts occurred during the non-crop season. Refinements and reported maximums are from this inventory.

4.4 RECEPTOR LOCATIONS

4.6.1 SIGNIFICANT IMPACT ANALYSIS

For short and long term averaging periods, concentrations were predicted at 252 receptors located in a radial grid centered on the proposed stacks for the Osceola cogeneration units. Receptors were located in "rings," with 36 receptors per ring spaced at 10-degree intervals at distances of 7, 11, 14, 20, 30, 40, 50, and 60 km.

4.6.2 AAQS IMPACT ASSESSMENTS

For the AAQS analysis, both near- and far-field receptor grids were used. Osceola Farms' and Osceola Power's nearest property boundary is located approximately 1.0 km from the stack locations. The near-field screening grids included 36 receptors for each 10 degree sector located on the following rings: at the plant property; 2, 4, and 6 km in directions outside plant property (distance to property boundary varies greatly by sector); and 8, 11, 14, 17, and 20 km. The far-field screening grid included six rings of receptors at distances of 25, 30, 40, 50, and 60 km.

In addition, a detailed screening grid was utilized in the AAQS analysis. This grid was centered on the near-field screening receptor at 270°, 6.0 km, which is near the U.S. Sugar Corporation's Bryant mill.

To the east of the proposed cogeneration facility, the Osceola site surrounds a parcel of land that is not owned or leased by either Osceola Power or Osceola Farms. For the analysis, this land was considered as accessible to the public (i.e., as ambient air).

The nearest property boundary receptors used for the screening modeling are presented in Table 4-5. All receptor locations are relative to the Osceola cogeneration facility co-located stack location.

4.6.3 PSD CLASS II IMPACT ASSESSMENTS

To cover the spatial extent of Osceola Power's significant impact area for SO_2 (60 km), near-field and far-field receptor grids were used for the PSD Class II screening analyses. The Class II screening grids were the same as the AAQS screening grids.

4.6.4 CLASS I IMPACT ASSESSMENT

The Everglades National Park is a PSD Class I area that is located beyond 100 km of the Okeelanta Power plant site. Through passage of the Clean Air Act of 1990, the park's eastern edge has been expanded farther to the east. The northeastern corner of the expanded Class I area is approximately 120 km south of the Osceola Power site (see Figure 4-1). In the screening analysis, Everglades National Park is represented by 51 discrete receptors, including 47 receptors covering the eastern and northern boundaries of the park from the Florida Keys to the Gulf of Mexico and 4 receptors inside the northeast corner of Everglades National Park. The Universal

Table 4-5. Property Boundary Receptors Used in the Modeling Analysis

Direction (degrees)	Distance (m)	Direction (degrees)	Distance (m)
10	3033	190	1040
20	3179	200	1090
30	3449	210	1183
40	3899	220	1337
50	4647	230	1592
60	2252	240	1408
70	2076	250	1297
80	1981	260	1238
90	1951	270	1219
100	2352	280	1238
110	2465	290	1297
120	2048	300	1408
130	1631	310	1592
140	1944	320	1897
150	2041	330	2438
160	1881	340	3179
170	1040	350	3033
180	1024	360	2987

Note: Distances are relative to the Osceola Power boilers stack location.

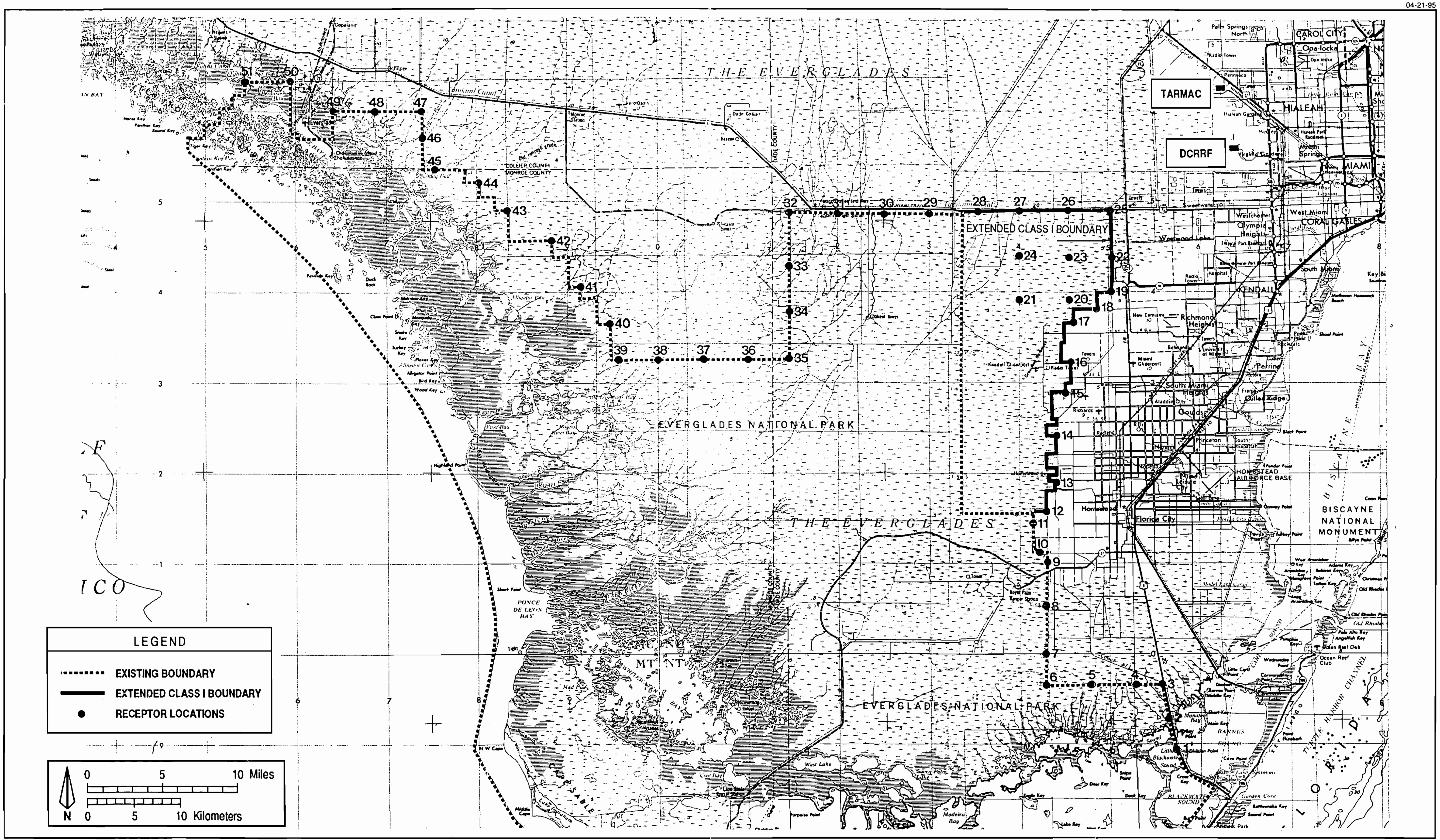

Figure 4-1
Receptor Locations Used for the Everglades National Park PSD Class I Screening Analyses

Transverse Mercator (UTM) coordinates of these Class I receptors are listed in Table 4-6. Refined modeling was performed for the Class I area by using a receptor spacing of 1.0 km centered on the receptor of interest extending to the adjacent receptors.

4.7 BUILDING DOWNWASH CONSIDERATIONS

The procedures used for addressing the effects of building downwash are those recommended in the ISC2 Dispersion Model User's Guide. The building height, length, and width are input to the model, which uses these parameters to modify the dispersion parameters. For short stacks (i.e., physical stack height is less than $H_b + 0.5\ L_b$, where H_b is the building height and L_b is the lesser of the building height or projected width), the Schulman and Scire (1980) method is used. The features of the Schulman and Scire method are as follows:

1. Reduced plume rise as a result of initial plume dilution,
2. Enhanced plume spread as a linear function of the effective plume height, and
3. Specification of building dimensions as a function of wind direction.

For cases where the physical stack is greater than $H_b + 0.5\ L_b$ but less than GEP, the Huber and Snyder (1976) method is used. For this method, the ISCST model calculates the area of the building using the length and width, assumes the area is representative of a circle, and then calculates a building width by determining the diameter of the circle. For both methods the direction-specific building dimensions are input for H_b and L_b for 36 radial directions, with each direction representing a 10-degree sector.

The existing Osceola Farms and proposed Osceola Power stacks have heights that are below that required to completely avoid building downwash effects. Therefore, the modeling analysis addresses the effects of aerodynamic downwash for these stacks. To determine the potential for downwash to occur, the following buildings were analyzed from a layout plan of the site.

Building	Height (m)	Length (m)	Width (m)
Existing Boiler Building	21.34	92.0	70.0
Proposed Boilers 1 & 2	36.88	42.0	23.0

The potential for downwash was determined for each 1 degree within each 10-degree direction sector. For each direction, a building structure was determined to be within the zone of influence of a stack if the stack is within $5L_b$ downwind off the building, $2L_b$ upwind of the building, or

Table 4-6. Everglades National Park Receptors Used for the Class I Screening Analyses

	UTM Coordinates (km)			UTM Coordinates (km)	
Receptor	East	North	Receptor	East	North
1	557.0	2789.0	27	540.0	2848.6
2	556.6	2792.0	28	535.0	2848.6
3	556.0	2796.0	29	530.0	2848.6
4	553.0	2796.5	30	525.0	2848.6
5	548.0	2796.5	31	520.0	2848.6
6	542.7	2796.5	32	515.0	2848.6
7	542.7	2800.0	33	515.0	2843.0
8	542.7	2805.0	34	515.0	2838.0
9	542.7	2810.0	35	515.0	2832.5
10	542.0	2811.0	36	510.0	2832.5
11	541.3	2814.0	37	505.0	2832.5
12	542.7	2816.0	38	500.0	2832.5
13	544.1	2820.0	39	495.0	2832.5
14	543.5	2824.6	40	494.5	2837.0
15	545.0	2829.0	41	491.5	2841.0
16	545.7	2832.2	42	488.5	2845.5
17	546.2	2835.7	43	483.0	2848.5
18	548.6	2837.5	44	480.0	2852.5
19	550.3	2839.0	45	475.0	2854.0
20	445.0	2839.0	46	473.5	2857.0
21	440.0	2839.0	47	473.5	2860.0
22	550.5	2844.0	48	469.0	2860.0
23	545.0	2844.0	49	464.0	2860.0
24	540.0	2844.0	50	459.5	2864.0
25	550.3	2848.6	51	454.0	2864.0
26	545.0	2848.6			

Note: km = kilometers.
UTM = Universal Transverse Mercator.

$0.5L_b$ crosswind of the building. Based on this analysis, direction-specific building heights and widths were developed using the EPA's Building Profile Input Program (BPIP, Version 95086) for each 10-degree direction sector and included for both existing and proposed stacks on the site.

4.8 BACKGROUND CONCENTRATIONS

To estimate total air quality concentrations, a background concentration must be added to the modeling results. The background concentration is considered to be the air quality concentration contributed by sources not included in the modeling evaluation.

In order to develop a conservative estimate of the SO_2 background with the existing Osceola boilers shut down, the highest 3-hour and 24-hour and highest annual average SO_2 concentrations measured at the Belle Glade monitor during the period 1991-1993 were used (refer to Table 4-7). Based on this analysis, the background SO_2 concentrations were determined to be 34 and 16 $\mu g/m^3$ for the 3- and 24-hour averaging periods, respectively, and 5 $\mu g/m^3$ for the annual averaging period. These background levels were added to model-predicted concentrations to estimate total air quality levels for comparison to AAQS.

4.9 AIR QUALITY MODELING RESULTS

4.9.1 SIGNIFICANT IMPACT ANALYSIS

The maximum air quality impacts from the proposed Osceola Power facility only are presented in Table 4-8. As shown, the facility's maximum annual, 24-hour, and 3-hour predicted SO_2 concentrations are 5.1, 66, and 183 $\mu g/m^3$, respectively. These all occur at the plant property boundary. These maximum impacts are above the respective SO_2 significant impact levels of 1, 5, and 25 $\mu g/m^3$. Therefore, a full impact assessment was performed for this pollutant to demonstrate compliance with allowable PSD increments and AAQS. It was determined that the distance of the total facility's significant impact for SO_2 is 60 km, based on the maximum 3-hour worst-case coal-burning emissions.

4.9.2 AAQS ANALYSIS

The results of the SO_2 screening modeling analyses for the near- and far-field receptor grid are presented in Tables 4-9 and 4-10 respectively. Results from a more detailed screening grid, centered about receptor location 270°, 6000 m, are presented in Table 4-11. This grid was analyzed because the screening analysis indicated maximum impacts for all averaging times may

Table 4-7. SO_2 Concentrations Measured at the Monitoring Station in Belle Glade

				Measured Concentration ($\mu g/m^3$)				
				3-Hour		24-Hour		
Site Number	Location	Period	Number of Observations	Highest	Second Highest	Highest	Second-Highest	Annual
3420-017-J02	Belle Glade: Duda Rd, 1 mile south of Old SR 80	Jan - Sept 1991	4,279	34	30	16	14	4
		Feb - Dec 1992	7,312	19	18	16	10	5
		Jan - Sept 1993	5,839	24	22	10	10	3

Table 4-8. Maximum Predicted SO_2 Concentrations for the Proposed Facility Only

Averaging Time	Concentration[a] ($\mu g/m^3$)	Receptor Location[b] Direction (degrees)	Receptor Location[b] Distance (m)	Period Ending (YYMMDDHH)
Annual	5.1	310.	2000.	82123124
	4.2	310.	2000.	83123124
	4.2	260.	4000.	84123124
	4.1	270.	2000.	85123124
	4.7	270.	2000.	86123124
24-Hour Highest	66	220.	1337.	82110724
	52	220.	1337.	83092524
	66	180.	1024.	84053124
	58	220.	1337.	85091424
	47	220.	1337.	86082324
24-Hour HSH[c]	61	220.	1337.	82110924
	41	220.	1337.	83061624
	46	220.	1337.	84100924
	38	290.	2000.	85090224
	47	220.	1337.	86101924
8-Hour Highest	106	310.	1592.	82091016
	131	300.	1408.	83062016
	106	210.	1183.	84090716
	97	290.	2000.	85090216
	105	250.	1297.	86060316
8-Hour HSH[c]	83	310.	1592.	82091216
	93	240.	1408.	83050616
	83	180.	1024.	84053124
	82	270.	1219.	85042016
	90	220.	1337.	86082316
3-Hour Highest	155	300.	1408.	82092015
	152	310.	1592.	83070615
	167	180.	1024.	84090812
	183	210.	1183.	85051515
	173	250.	1297.	86060312
3-Hour HSH	129	280.	2000.	82051212
	147	310.	1592.	83060412
	154	180.	1024.	84053118
	147	270.	1219.	85042415
	145	220.	1337.	86042915

Note: YY=Year, MM=Month, DD=Day, HH=Hour

[a] Maximum concentrations indicated are for the proposed facility with no offsets.

[b] All receptor coordinates are reported with respect to the midpoint of the proposed Osceola Power Cogeneration facility stacks.

[c] Highest, second-highest (HSH) concentrations shown.

Table 4-9. Maximum Predicted SO_2 Concentrations for the AAQS Screening Analysis, Near-Field Receptors

Averaging Time	Concentration ($\mu g/m^3$)	Receptor Location[a] Direction (degrees)	Receptor Location[a] Distance (m)	Period Ending (YYMMDDHH)
Annual	27	220.	17000.	82123124
	22	220.	17000.	83123124
	24	270.	6000.	84123124
	23	270.	8000.	85123124
	25	270.	6000.	86123124
24-Hour[b]	131	220.	17000.	82073024
	146	220.	17000.	83040724
	169	210.	17000.	84022824
	133	280.	6000.	85082424
	141	270.	8000.	86110724
3-Hour[b]	727	270.	6000.	82070612
	858	280.	6000.	83101312
	963	270.	6000.	84040212
	937	270.	6000.	85090812
	938	270.	6000.	86100112

Note: YY=Year, MM=Month, DD=Day, HH=Hour

[a] All receptor coordinates are reported with respect to the midpoint of the Osceola Power Cogeneration facility stacks.

[b] All short-term concentrations indicate highest, second-highest concentrations.

Table 4-10. Maximum Predicted SO_2 Concentrations for the AAQS Screening Analysis, Far-Field Receptors

Averaging Time	Concentration ($\mu g/m^3$)	Receptor Location[a] Direction (degrees)	Receptor Location[a] Distance (m)	Period Ending (YYMMDDHH)
Annual	22	120.	50000.	82123124
	18	120.	50000.	83123124
	24	120.	50000.	84123124
	22	120.	50000.	85123124
	22	120.	50000.	86123124
24-Hour[b]	146	120.	50000.	82100324
	153	160.	25000.	83061624
	160	160.	25000.	84090624
	133	120.	50000.	85111424
	132	160.	25000.	86102024
3-Hour	422	160.	25000.	82112218
	466	160.	25000.	83082418
	587	160.	25000.	84011515
	460	160.	25000.	85092515
	421	160.	25000.	86101718

Note: YY=Year, MM=Month, DD=Day, HH=Hour

[a] All receptor coordinates are reported with respect to the midpoint of the Osceola Power Cogeneration facility stacks.

[b] All short-term concentrations indicate highest, second-highest concentrations.

Table 4-11. Maximum Predicted SO_2 Concentrations for the AAQS Detailed Screening Analysis Grid[a]

Averaging Time	Concentration ($\mu g/m^3$)	Receptor Location[b] Direction (degrees)	Receptor Location[b] Distance (m)	Period Ending (YYMMDDHH)
Annual	32	276.	6200.	82123124
	27	276.	6200.	83123124
	32	270.	6500.	84123124
	29	270.	6500.	85123124
	31	270.	6500.	86123124
24-Hour[c]	169	276.	6200.	82070724
	165	278.	6200.	83072024
	208	270.	6500.	84121524
	167	270.	6500.	85041224
	182	270.	6900.	86110724
3-Hour[c]	1,059	272.	6200.	82070515
	1,037	276.	5900.	83072012
	1,013	276.	5900.	84073112
	1,054	274.	6200.	85042615
	984	274.	5900.	86051215

Note: YY=Year, MM=Month, DD=Day, HH=Hour

[a] Centered on screening grid receptor location (6000 m, 270°).

[b] All receptor coordinates are reported with respect to the midpoint of the Osceola Power Cogeneration facility stacks.

[c] All short-term concentrations indicate highest, second-highest concentrations.

be located in this area. The maximum annual, 24-hour, and 3-hour impacts from the screening analysis are 32, 208, and 1,059 $\mu g/m^3$, respectively. For all averaging times, maximum concentrations were predicted approximately 6.0 km from the Osceola Power site. The maximum concentrations were caused primarily by other modeled sources. The results indicate that the maximum SO_2 concentrations will not exceed SO_2 AAQS at any location in the vicinity of the Osceola Power plant.

Based on the screening analysis, refinements were performed for all averaging periods. The refined concentrations, including background SO_2 levels, are presented in Table 4-12. The predicted maximum annual, 24-hour, and 3-hour concentrations are 38, 224, and 1,093 $\mu g/m^3$, respectively. These predicted maximum impacts are due primarily to sources other than Osceola Power, and are located approximately 6 km from the Osceola Power site. This analysis indicates that AAQS will be met at locations within the SIA. Source contributions for refined maximums are detailed in Appendix F.

4.9.3 PSD CLASS II ANALYSIS

The results of the PSD Class II screening analysis for the near-field and far-field receptor grids are presented in Tables 4-13 and 4-14, respectively. Based on the screening results, refined modeling analyses were performed for each averaging time. For the refined analysis for the 24-hour averaging time, the crop and off-season time periods were modeled separately, with the sugar mill sources operating only during the wintertime crop season period. Source contributions for refined maximums are detailed in Appendix F.

The refined results, summarized in Table 4-15, indicate that the maximum SO_2 PSD Class II increment consumption will not exceed the allowable PSD increments. The maximum annual, 24-hour, and 3-hour predicted increment consumption of 10.7, 76, and 191 $\mu g/m^3$, respectively, are below the allowable PSD Class II increments of 20, 91, and 512 $\mu g/m^3$. The maximum increment consumption values are due primarily to sources other than Osceola Power, and occur approximately 7 km from the Osceola Power site.

4.9.4 PSD CLASS I ANALYSIS

The SO_2 PSD Class I screening grid modeling results using the ISCST2 model, are presented in Tables 4-16 and 4-17. The refined modeling results are presented in Table 4-18. The refined

Table 4-12. Maximum Predicted SO_2 Concentrations as Compared With AAQS - Refined Analysis

	Concentration ($\mu g/m^3$)			Receptor Locations[a]			
Averaging Time	Total	Modeled	Background	Direction (degrees)	Distance (m)	Period Ending (YYMMDDHH)	Florida AAQS ($\mu g/m^3$)
Annual	38	33	5	277	6,200	82123124	60
	37	32	5	270	6,400	84123124	
	38	33	5	271	6,400	86123124	
24-Hour[b]	224	208	16	270	6,600	84121524	260
3-Hour[b]	1,093	1,059	34	272	6,200	82070515	1,300
	1,088	1,054	34	274	6,200	85042615	

Note: YY=Year, MM=Month, DD=Day, HH=Hour

[a] Receptors locations are relative to the midpoint of the Osceola Power Cogeneration facility stacks.

[b] All short-term concentrations are highest, second-highest concentrations.

Table 4-13. Maximum Predicted SO_2 Concentrations for the PSD Class II Screening Analysis, Near-Field Receptors

Averaging Time	Concentration ($\mu g/m^3$)	Receptor Location[a] Direction (degrees)	Receptor Location[a] Distance (m)	Period Ending (YYMMDDHH)
Annual	8.0	270.	8000.	82123124
	6.1	310.	2000.	83123124
	8.9	270.	8000.	84123124
	8.2	270.	8000.	85123124
	9.0	270.	8000.	86123124
24-Hour[b]	61	220.	1337.	82110924
	51	220.	1337.	83061624
	62	270.	8000.	84112624
	53	270.	8000.	85111524
	68	270.	8000.	86110724
3-Hour[b]	144	270.	8000.	82012803
	147	310.	1592.	83060412
	174	180.	1024.	84090812
	170	270.	6000.	85070315
	156	270.	6000.	86053115

Note: YY=Year, MM=Month, DD=Day, HH=Hour

[a] All receptor coordinates are reported with respect to the midpoint of the Osceola Power Cogeneration facility stacks.

[b] All short-term concentrations indicate highest, second-highest concentrations.

Table 4-14. Maximum Predicted SO_2 Concentrations for the PSD Class II Screening Analysis, Far-Field Receptors

Averaging Time	Concentration ($\mu g/m^3$)	Receptor Location[a] Direction (degrees)	Receptor Location[a] Distance (m)	Period Ending (YYMMDDHH)
Annual	5.4	350.	25000.	82------
	4.4	350.	25000.	83------
	5.1	350.	25000.	84------
	5.3	350.	25000.	85------
	5.6	350.	25000.	86------
24-Hour[b]	29	220.	40000.	82050524
	29	350.	25000.	83043024
	30	220.	40000.	84122624
	29	350.	25000.	85102124
	25	220.	40000.	86010824
3-Hour[b]	88	220.	30000.	82060524
	94	220.	30000.	83122906
	98	350.	25000.	84070512
	100	350.	25000.	85090812
	86	220.	30000.	86072609

Note: YY=Year, MM=Month, DD=Day, HH=Hour

[a] All receptor coordinates are reported with respect to the midpoint of the Osceola Power Cogeneration facility stacks.

[b] All short-term concentrations indicate highest, second-highest concentrations.

Table 4-15. Maximum Predicted SO_2 Concentrations as Compared with PSD Class II Increments - Refined Analysis

Averaging Time	Concentration ($\mu g/m^3$)	Receptor Location[a] Direction (degrees)	Receptor Location[a] Distance (m)	Period Ending (YYMMDDHH)	Allowable Increment ($\mu g/m^3$)
Annual	10.5	269	6800	84123124	20
	10.7	270	7000	86123124	
24-Hour[b]	63	222.	1400.	82110924	91
	76	268.	7600.	84121524	
	76	270.	7100.	86110724	
3-Hour[b]	174	180.	1100.	84090812	512
	186	274.	6300.	85042615	
	191	276.	6200.	86051215	

Note: YY=Year, MM=Month, DD=Day, HH=Hour

[a] All receptor coordinates are with respect to Osceola Power Cogeneration facility's co-located stack location.

[b] All short-term concentrations are highest, second-highest concentrations.

Table 4-16. Maximum Predicted SO_2 Concentrations for the PSD Class I Screening Analysis, Off-Season[a]

Averaging Time	Concentration ($\mu g/m^3$)	Receptor Location[b] UTM-E (m)	Receptor Location[b] UTM-N (m)	Period Ending (YYMMDDHH)
Annual	0.48	550300.	2848600.	82------
	0.58	550300.	2848600.	83------
	0.47	550300.	2848600.	84------
	0.41	545000.	2848600.	85------
	0.41	550300.	2848600.	86------
24-Hour[c]	3.92	500000.	2832500.	82081524
	5.05	550300.	2839000.	83081724
	3.85	535000.	2848600.	84053124
	3.38	546200.	2835700.	85040824
	3.03	550300.	2848600.	86033024
3-Hour[c]	18.4	500000.	2832500.	82071621
	18.2	545000.	2848600.	83061609
	16.4	540000.	2839000.	84041121
	16.9	545000.	2844000.	85032521
	15.9	491500.	2841000.	86041824

Note: YY=Year, MM=Month, DD=Day, HH=Hour

[a] Maximum period during which sugar mills are not operating, which extends from 3/1 through 10/31.

[b] All receptor coordinates are reported in Universal Transverse Mercator (UTM) coordinates.

[c] All short-term concentrations indicate highest, second-highest concentrations.

Table 4-17. Maximum Predicted SO_2 Concentrations for the PSD Class I Screening Analysis, Crop Season[a]

Averaging Time	Concentration ($\mu g/m^3$)	Receptor Location[b] UTM-E (m)	 UTM-N (m)	Period Ending (YYMMDDHH)
Annual	0.43	550300.	2848600.	82------
	0.38	540000.	2848600.	83------
	0.41	540000.	2848600.	84------
	0.35	535000.	2848600.	85------
	0.31	545000.	2848600.	86------
24-Hour[c]	3.31	545000.	2848600.	82112324
	3.96	540000.	2848600.	83101624
	3.03	545000.	2844000.	84011324
	3.33	535000.	2848600.	85022024
	2.85	545000.	2848600.	86033024
3-Hour[c]	15.4	545000.	2848600.	82112318
	15.2	542700.	2816000.	83040406
	15.3	540000.	2848600.	84030409
	15.2	535000.	2848600.	85031109
	14.5	530000.	2848600.	86102806

Note: YY=Year, MM=Month, DD=Day, HH=Hour

[a] Maximum period during which sugar mills are operating, which extends from 10/1 through 4/30.

[b] All receptor coordinates are reported in Universal Transverse Mercator (UTM) coordinates.

[c] All short-term concentrations indicate highest, second-highest concentrations.

Table 4-18. Maximum Predicted SO_2 Concentrations as Compared with PSD Class I Increments - Refined Analysis

Averaging Time	Concentration ($\mu g/m^3$)	Receptor Location[a] UTM-E (m)	UTM-N (m)	Period Ending (YYMMDDHH)	Allowable Increment ($\mu g/m^3$)
Annual	0.60	549000.	2848600.	83123124	2
24-Hour[b]	4.10[c]	550300.	2839000.	83081724	5
3-Hour[b]	22.8	497000.	2830500.	82071621	25
	20.4	542000.	2848600.	83081621	

Note: YY=Year, MM=Month, DD=Day, HH=Hour

[a] All receptor coordinates are reported in Universal Transverse Mercator (UTM) coordinates.
[b] All short-term concentrations are highest, second-highest concentrations.
[c] Obtained using MESOPUFF II model for refined analysis (see Appendix F).

results indicate that the maximum annual, 24-hour, and 3-hour PSD increment consumed at the expanded Everglades National Park are 0.60, 4.10, and 22.8 $\mu g/m^3$, respectively. Source contributions for refined maximums are detailed in Appendix F. These impacts are below the allowable PSD Class I increments of 2, 5, and 25 $\mu g/m^3$ for the annual, 24-hour, and 3-hour averaging times, respectively. The proposed facility with other increment consuming sources, therefore, will not exceed the allowable PSD increments in the Class I area.

It is noted that the screening analysis with ISCST2 model indicates that the 24-hour Class I increment of 5 $\mu g/m^3$ may be exceeded in the Class I area, but only during one 24-hour period in the 5-year meteorological database (1983). Analysis of the source contributions to these maximums shows that the Osceola Power cogeneration project contributes 1.13 $\mu g/m^3$ to the predicted HSH concentration, which is greater than the National Park Service's recommended 24-hour SO_2 Class I significance level of 0.07 $\mu g/m^3$.

Based on the ISCST2 PSD Class I screening modeling results, a supplemental air quality analysis was performed with the MESOPUFF II long-range transport model. As discussed in Appendix E, a long-range transport model is more appropriate for estimating maximum impacts for the cogeneration facility, because the facility is located 120 km from the Class I area. MESOPUFF II is a more accurate model than ISCST2 when evaluating impacts at such a distance. This is consistent with the past applications of the model by FDEP, EPA, and the National Park Service.

The MESOPUFF II modeling results indicate that Osceola Power's contribution to the HSH ISCST2 impact is 0.18 $\mu g/m^3$, which is lower than the ISCST2 predicted values. Therefore, from Table F-1, substitution of the cogeneration facility's contribution reduces the total source predicted impacts to 4.10 $\mu g/m^3$. This concentration is less than the allowable 24-hour PSD increment of 5 $\mu g/m^3$. Therefore, the cogeneration facility will comply with all allowable SO_2 PSD Class I increments.

4.9.5 TOXIC IMPACT ANALYSIS

The maximum impacts of regulated and nonregulated toxic air pollutants that will be emitted by the Osceola Power facility are presented in Table 4-19. Each pollutant's maximum 8-hour, 24-hour, and annual impact is compared to the respective FDEP ARC. The table shows that all toxic pollutant impacts will be below respective ARCs, except for arsenic for the annual averaging

Table 4-19. Maximum Impacts of Florida Air Toxic Pollutants for Osceola Power Cogeneration Facility (total both boilers)

Pollutant	Maximum Hourly Emissions[a] (lb/hr)	Maximum Annual Emissions[a] (lb/hr)	Concentrations ($\mu g/m^3$)					
			8-Hour		24-Hour		Annual	
			Impact	ARC	Impact	ARC	Impact	ARC
Acetaldehyde	1.19	1.19	0.12	1,800	0.069	432	0.0048	0.45
Acetone	0.58	0.58	0.061	36,500	0.033	8,544	--	--
Acetophenone	0.0056	0.0056	--	--	--	--	2.24E-05	100
Acrolein	0.099	0.099	0.010	2.3	0.0057	0.552	0.00040	0.02
Ammonia	50.80	50.80	5.32	170	2.93	40.8	0.20	100
Antimony	0.037	0.037	0.0039	5	0.0021	1.2	0.00015	0.3
Arsenic	0.2	0.065	0.021	1.6	0.012	0.48	0.00026	0.00023
Barium	0.078	0.078	0.0082	5	0.0045	1.2	0.00031	50
Benzene	1.98	1.98	0.21	30	0.11	7.2	0.0079	0.12
Benzo(a)anthracene	0.0011	0.0011	--	--	--	--	4.57E-06	0.0011
Benzo(a)pyrene	5.36E-05	5.36E-05	--	--	--	--	--	--
Beryllium	0.0062	0.0062	0.00065	0.02	0.00036	0.0048	2.48E-05	0.00042
Bromine	0.080	0.080	0.0084	6.6	0.0046	1.584	--	--
Cadmium	0.0013	0.0013	0.00014	0.5	7.50E-05	0.12	5.21E-06	0.00056
Carbon Disulfide	0.20	0.20	0.021	310	0.012	74.4	0.00080	200
Carbon Tetrachloride	0.0091	0.0091	0.00095	310	0.00052	74.4	3.65E-05	0.067
Chlorine	1.40	1.40	0.15	15	0.081	3.6	0.0056	0.4
Chloroform	0.071	0.071	0.0074	490	0.0041	117.6	0.00028	0.043
Chromium	0.24	0.077	0.025	5	0.014	1.2	--	--
Chromium (VI)	0.048	0.016	0.0050	0.5	0.0028	0.12	6.41E-05	8.30E-05
Chrysene	0.054	0.054	--	--	--	--	--	--
Cobalt	0.076	0.076	0.0080	0.5	0.0044	0.12	--	--
Copper	0.19	0.075	0.020	10	0.011	2.4	--	--
Cumene	0.027	0.027	0.0028	2,460	0.0016	590.4	0.00011	1
Di - n - Butyl Phthalate	0.088	0.088	0.0092	50	0.0051	12	0.00035	100
Ethyl Benzene	0.0059	0.0059	0.00062	4,340	0.00034	1,042	2.36E-05	1,000
Fluorides	25.24	25.24	2.65	25	1.46	6	--	--
Formaldehyde	1.98	1.98	0.21	12	0.11	2.88	0.0079	0.077
Hydrogen Chloride	83.74	83.74	8.78	75	4.83	18	0.34	7
Indium	0.20	0.20	0.021	1	0.012	0.24	--	--
Iodine	0.0032	0.0032	0.00034	10	0.00018	2.4	--	--
Isopropanol	13.98	13.98	1.47	9,830	0.81	2,539	--	--
Lead	0.0054	0.068	0.00057	0.5	0.00031	0.12	0.00027	0.09
m & p Xylene	0.012	0.012	0.0013	4,340	0.00069	1,042	4.81E-05	80
Manganese	0.14	0.14	0.015	50	0.0081	12	--	--
Mercury	0.0090	0.0088	0.00094	0.5	0.00052	0.12	3.53E-05	0.3
Methanol	2.28	2.28	0.24	2,620	0.132	628.8	--	--
Methyl Ethyl Ketone	0.018	0.018	0.0019	5,900	0.0010	1416	7.21E-05	80
Methyl Isobutyl Ketone	1.31	1.31	0.14	2,050	0.076	492	--	--
Methylene Chloride	2.28	2.28	0.24	1,740	0.13	417.6	0.0091	2.1
Molybdenum	0.0094	0.0094	0.00099	50	0.00054	12	--	--
n Hexane	0.84	0.84	0.088	1,760	0.048	422.4	0.0034	200
Napthalene	0.90	0.90	0.094	520	0.052	124.8	--	--
Nickel	0.011	0.011	0.0012	10	0.00063	2.4	4.41E-05	0.0042
o Xylene	0.004	0.004	0.00042	4,340	0.00023	1,042	1.60E-05	80

Table 4–19. Maximum Impacts of Florida Air Toxic Pollutants for Osceola Power Cogeneration Facility (total both boilers)

Pollutant	Maximum Hourly Emissions[a] (lb/hr)	Maximum Annual Emissions[a] (lb/hr)	Concentrations ($\mu g/m^3$)					
			8–Hour		24–Hour		Annual	
			Impact	ARC	Impact	ARC	Impact	ARC
PAH	––	––	––	2	––	48	––	––
Phenols	0.062	0.062	0.0065	190	0.0036	45.6	0.00025	30
Phosphorous	0.91	0.91	0.10	1	0.052	0.24	––	––
POM (Polycyclic Organic Matter)	0.00033	0.00033	––	––	––	––	––	––
Selenium	0.057	0.057	0.0060	2	0.0033	0.48	––	––
Silver	0.0022	0.0022	0.00023	1	0.00013	0.24	8.81E–06	3
Styrene	0.023	0.023	0.0024	2,130	0.0013	517.2	––	––
Sulfuric acid mist	10.60	37.88	1.11	10	0.61	2.4	––	––
Thallium	––	––	––	1	––	0.24	––	0.5
Tin	0.0094	0.0094	0.00099	20	0.00054	4.8	––	––
Toluene	0.14	0.14	0.015	3,770	0.0081	904.8	0.00056	300
2,3,7,8 Tetrachlorodibenzo–p–dioxin	9.12E–09	9.12E–09	––	––	––	––	3.65E–11	2.2E–08
Trichloroethylene	0.012	0.012	0.0013	2,690	0.00069	645.6	––	––
'1,1,1 Trichloroethane	0.26	0.26	0.027	38,200	0.015	9,168	––	––
Tungsten	1.96E–05	1.96E–05	2.05E–06	50	1.13E–06	12	––	––
Vanadium	0.00022	0.00022	2.31E–05	0.50	1.27E–05	0.12	8.81E–07	20
Yttrium	0.00010	0.00010	1.05E–05	10	5.77E–06	2.4	––	––
Zirconium	0.00062	0.00062	6.50E–05	50	3.58E–05	12	––	––

Note: ARC = air reference concentration

Maximum concentrations determined with ISCST2 model and West Palm Beach meteorological data for 1982 to 1986.

Highest predicted concentrations ($\mu g/m^3$) for a 10 g/s (79.365 lb/hr) emission rate assuming coal burning stack parameters:

8–Hour = 8.317, 24–Hour = 4.578 , and Annual = 0.318

[a] Total both boilers.

time. These arsenic impacts are based on a conservative analysis which assumes 2.4 percent of the wood waste steam for the facility is treated wood. The annual ARC for arsenic is 0.00023 $\mu g/m^3$.

Review of the modeling results for arsenic show that the annual ARC is predicted to be met at a distance of 4 km and beyond from the cogeneration facility. There are no residences or other public or private buildings, other than Osceola Farms buildings, located within 4 km of the proposed facility. This area consists totally of sugar cane fields. In addition, the ARC is based on a 1 in 1 million risk of cancer. EPA has promulgated risk factors for toxic substances, including arsenic, based on a 1 in 100,000 risk of cancer. The predicted maximum annual impact of arsenic of 0.00026 $\mu g/m^3$ is well below the EPA promulgated level of 0.0023 $\mu g/m^3$ based on 1 in 100,000 risk. Based on these considerations, no adverse effects due to the cogeneration facility are expected.

4.10 OPERATION OF COGENERATION BOILERS IN CONJUNCTION WITH EXISTING OSCEOLA BOILERS

During initial startup of the cogeneration facility prior to commercial operation, it is possible the cogeneration boilers may be operated when the Osceola sugar mill boilers are also operating. This situation may arise when performance tests and debugging activities are conducted at the cogeneration facility.

It is expected that such operations will occur no more than 120 calendar days during the initial 12-months following cogeneration plant startup. This will not be a consecutive 120 day period, but will instead consist of intermittent periods of performance testing and debugging until commercial operation begins. During these 120 calendar days, only biomass or No. 2 fuel oil will be burned in the cogen boilers. Coal will not be burned during this period. Simultaneous operation of the existing and new facilities will only occur during the crop season, because the existing Osceola sugar mill boilers do not operate during the seven-month off-season.

The testing of the cogeneration boilers prior to commercial operation will be performed in isolation (i.e., no steam being sent to the sugar mill) or in the cogeneration mode (i.e., with steam being sent to the sugar mill). When operating in isolation, the maximum short-term (i.e., 3-hour) steam load that can be accommodated totally within the cogeneration facility is both boilers operating at full load (1,012,000 lb/hr steam). On a 24-hour average basis, the maximum steam load will be limited to 570,000 lb/hr steam.

In order to investigate the potential air quality impacts of this situation, air dispersion modeling of the cogen boilers for biomass burning conditions was performed (i.e., emissions and gas flow rate are different than under coal burning conditions). Emissions equivalent to two boilers at full load were modeled for the 1-, 3- and 8-hour averaging times, and emissions equivalent to 570,000 lb/hr steam were modeled for the 24-hour and annual averaging times (Table 4-20). The results of this analysis are presented in Table 4-21. As shown, the maximum cogen facility impacts are all less than the air quality significant impact levels. This demonstrates that the cogen facility, when operated at or below these steam rates, will not contribute significantly to any existing air quality impacts (e.g., those due to the existing sugar mill boilers).

Class I PSD impacts were also analyzed for this case of simultaneous operation during the crop season. Presented in Table 4-22 are the predicted Class I impacts of the cogeneration boilers only burning biomass with 1) two boilers operating at full load for the 3-hour averaging time, and 2) with a total of 570,000 lb/hr steam for the 24-hour and annual averaging times. As shown, all impacts except the SO_2 24-hour and 3-hour impacts are below the National Park Service significance levels. Therefore, simultaneous operation of the existing boilers and cogen boilers during the crop season will not cause or contribute to any PSD Class I increment violations for PM or NO_x in the Class I area.

A comparison of the SO_2 emissions for the Class I modeling and the potential case of simultaneous operation is presented in Table 4-23. As shown, for Osceola Farms the PSD baseline SO_2 emissions are 335.3 lb/hr. Future SO_2 emissions for Osceola Power in the Class I modeling analysis (with coal) are 1,272 lb/hr, whereas for simultaneous operation the total SO_2 emissions (with biomass) will be 719.1 lb/hr, maximum 3-hour averaging time. Thus, SO_2 emissions during the proposed simultaneous operations are reduced by 553 lb/hr compared to the Class I modeling and therefore PSD Class I impacts should be reduced for this case.

The cogeneration facility may also be tested at times when the cogeneration plant is operated in the cogeneration mode. During this mode, steam will be sent from the cogen facility to the sugar mill, and the sugar mill boilers steam production will be reduced by an equal amount. Under

Table 4-20. Cogen Facility Emissions When Burning Biomass, Osceola Power

Boiler	Design Steam Rate Per Boiler (lb/hr)	Design Heat Input Per Boiler (MMBTU/HR)	Biomass Emission Factor (lb/MMBtu)				Biomass Emissions (lb/hr)				Biomass Emissions (lb/1000 lb steam)			
			SO2	NOx	PM	CO	SO2	NOx	PM	CO	SO2	NOx	PM	CO
							Maximum 3-Hour Load Case							
1	506,000	760	0.10	0.116	0.03	0.35	76.0	88.2	22.8	266.0	0.150	0.174	0.045	0.526
2	506,000	760	0.10	0.116	0.03	0.35	76.0	88.2	22.8	266.0	0.150	0.174	0.045	0.526
Total	1,012,000	1,520					152.0	176.3	45.6	532.0				
							Maximum 24-Hour (570,000) lb/hr Steam Case							
1	506,000	760	0.10	0.116	0.03	0.35	76.0	88.2	22.8	266.0	0.150	0.174	0.045	0.526
2	64,000	100	0.10	0.116	0.03	0.35	10.0	11.6	3.0	35.0	0.156	0.181	0.047	0.547
Total	570,000	860					86.0	99.8	25.8	301.0				

Note: All figures derived from permit application.

Table 4–21. Maximum Impacts of Osceola Cogeneration Facility Only When Operating Simultaneously With Existing Boiler

Parameter	Pollutant			
Emission Rate [1]	SO2	NOx	CO	PM
1–hour, 3–hour, 8–hour (lb/hr)	152.0	––	532.0	––
1–hour, 3–hour, 8–hour (g/s)	19.2	––	67.0	––
24–hour and Annual (lb/hr)	86.0	99.8	––	25.8
24–hour and Annual (g/s)	10.8	12.6	––	3.3
Maximum Impacts and Significance Levels ($\mu g/m^3$) [2]				
Annual Max Impact	0.35	0.40	––	0.10
Sig. Level	1	1	––	1
24–hour Max Impact	4.4	––	––	1.3
Sig. Level	5	––	––	5
8–hour Max Impact	––	––	38.3	––
Sig. Level	––	––	500	––
3–hour Max Impact	16.2	––	––	––
Sig. Level	25	––	––	––
1–hour Max Impact	––	––	119.8	––
Sig. Level	––	––	2,000	––

Notes:

[1] Burning biomass with emissions equivalent to two boilers at full load (1,012,000 lb/hr steam) for 3–hour averaging time and 570,000 lb/hr total steam rate for 24–hour and annual averaging time.

[2] Maximum impacts are based on cogeneration facility only operating during sugar mill season, October 1 through April 30. Impacts are the maximum refined impacts predicted using 1982 – 1986 meteorological data from West Palm Beach.
Signifigance Levels are PSD Class II Significant Levels.

Table 4-22. Maximum Impacts of Osceola Cogeneration Facility Only When Operating Simultaneously with Existing Boilers - Class I Area

	Emission Rate[1]			Maximum Impacts ($\mu g/m^3$)[2]			Nat'l Park Service Sig. Levels ($\mu g/m^3$)		
Pollutant	Averaging Time	(lb/hr)	(g/s)	Annual	24-hour	3-hour	Annual	24-hour	3-hour
SO2	3-hour	152.0	19.2	--	--	1.06	--	--	0.48
SO2	24-hour, Annual	86.0	10.8	0.006	0.159	--	0.03	0.07	--
NOx	Annual	99.8	12.6	0.007	--	--	0.025	--	--
PM	24-hour, Annual	25.8	3.3	0.002	0.048	--	0.1	0.33	--

Notes

[1] Burning biomass, with emissions equivalent to two boilers at full load (1,012,000 lb/hr steam) for 3-hour averaging time and 570,000 steam for 24-hour and annual averaging times.

[2] Based on cogeneration facility operating during sugar mill crop season, 10/1 - 4/30. Impacts based on highest concentration predicted using 1982-86 meteorological data.

Table 4–23. SO2 Emissions for Osceola Power Used in PSD Class I Analysis

Source	Basis of Class 1 Modeling (lb/hr)	Simultaneous Operation of Existing/Cogen Boilers (lb/hr)
	PSD Baseline	PSD Baseline
Boiler 1	40.2	40.2
Boiler 2	129.5	129.5
Boiler 3	57.6	57.6
Boiler 4	108.0	108.0
Boiler 5	--	--
Boiler 6	--	--
Boiler 10	--	--
Boiler 11	--	--
Boiler 12	--	--
Boiler 14	--	--
Boiler 15	--	--
Boiler 16	--	--
Totals	335.3	335.3
	Future	Future
Boiler 1	--	--
Boiler 2	--	77.9
Boiler 3	--	36.5
Boiler 4	--	77.9
Boiler 5	--	139.1
Boiler 6	--	235.7
Boiler 10	--	--
Boiler 11	--	--
Boiler 12	--	--
Boiler 14	--	--
Boiler 15	--	--
Boiler 16	--	--
Cogen Boilers	1,272.0 *	152.0 **
Totals	1,272.0	719.1

* Cogen facility boilers operating on 100% coal.

** Cogen boilers operating on biomass and at full load.

these conditions, air emissions and air impacts due to the existing Osceola Farms boilers will be reduced. For each lb of steam generated, emissions are higher from the existing boilers than from the cogen boilers. The calculation of maximum emissions from the existing boilers is presented in Table 4-24, and those for the cogen boilers are shown in Table 4-20. The comparison of emissions from the existing and cogen boilers is presented in Table 4-25.

In addition, the cogeneration stacks (200 ft) are higher than the existing boiler stacks (90 ft) and the cogeneration boiler exhaust gases (295°F) are of greater temperature than the existing boilers exhaust gases (150°F), and therefore the cogen boilers provide much greater dispersion of emissions. This demonstrates that any operation of the cogen boilers which sends steam to the sugar mill will only reduce total emissions and impacts.

Table 4–24. Existing Boiler Emissions, Osceola Sugar Mill

Boiler	Design Steam Rate (lb/hr)	Design Heat Input (MMBtu/hr)	Fuel Oil		Bagasse		Emission Factor (lb/MMBtu)		Emissions				
			gal/hr	MMBtu/hr	MMBtu/hr	lb/hr(dry)	Fuel Oil	Bagasse	Oil (lb/hr)	Bagasse+ (lb/hr)	Total (lb/hr)	Total (lb/MMBtu)	Total (lb/1000 lb steam)
				WORST CASE 24–HOUR SO2 EMISSIONS									
2	140,000	272	117	17.6	254.4	31,805	2.62	0.125	46.1	31.8	77.9	0.286	0.56
3	150,000	292	0	0.0	292.0	36,500	--	0.125	0.0	36.5	36.5	0.125	0.24
4	140,000	272	117	17.6	254.4	31,805	2.62	0.125	46.1	31.8	77.9	0.286	0.56
5	165,000	321	264	39.6	281.4	35,173	2.62	0.125	103.9	35.2	139.1	0.433	0.84
6	195,000	379	502	75.4	303.6	37,951	2.62	0.125	197.7	38.0	235.7	0.622	1.21
Totals		1,536	1,000	150.1	1,385.9	173,235			393.8	173.2	567.0		
				WORST CASE 24–HOUR NOx EMISSIONS									
2	140,000	272	117	17.6	254.4	31,805	0.446	0.235	7.8	59.8	67.6	0.249	0.48
3	150,000	292	0	0.0	292.0	36,500	--	0.16[1]	0.0	46.7	46.7	0.160	0.31
4	140,000	272	117	17.6	254.4	31,805	0.446	0.235	7.8	59.8	67.6	0.249	0.48
5	165,000	321	264	39.6	281.4	35,173	0.446	0.235	17.7	66.1	83.8	0.261	0.51
6	195,000	379	502	75.4	303.6	37,951	0.400[1]	0.16[1]	30.2	48.6	78.7	0.208	0.40
Totals		1,536	1,000	150.1	1,385.9	173,235			63.5	281.0	344.5		
				WORST CASE 24–HOUR PM EMISSIONS									
2	140,000	272	0	0.0	272.0	34,000	0.1[1]	0.20[1]	0.0	54.4	54.4	0.200	0.39
3	150,000	292	0	0.0	292.0	36,500	--	0.20[1]	0.0	58.4	58.4	0.200	0.39
4	140,000	272	0	0.0	272.0	34,000	0.1[1]	0.30[1]	0.0	81.6	81.6	0.300	0.58
5	165,000	321	0	0.0	321.0	40,125	0.1[1]	0.20[1]	0.0	64.2	64.2	0.200	0.39
6	195,000	379	0	0.0	379.0	47,375	0.1[1]	0.15[1]	0.0	56.9	56.9	0.150	0.29
Totals		1,536	0	0.0	1,536.0	192,000			0.0	315.5	315.5		
				WORST CASE 24–HOUR CO EMISSIONS									
2	140,000	272	0	0.0	272.0	34,000	0.033	3.625	0.0	986.0	986.0	3.625	7.04
3	150,000	292	0	0.0	292.0	36,500	--	3.625	0.0	1,058.5	1,058.5	3.625	7.06
4	140,000	272	0	0.0	272.0	34,000	0.033	3.625	0.0	986.0	986.0	3.625	7.04
5	165,000	321	0	0.0	321.0	40,125	0.033	3.625	0.0	1,163.6	1,163.6	3.625	7.05
6	195,000	379	0	0.0	379.0	47,375	0.033	3.625	0.0	1,373.9	1,373.9	3.625	7.05
Totals		1,536	0	0.0	1,536.0	192,000			0.0	5,568.0	5,568.0		

+ Assumes 50% SO2 removal when burning bagasse.
Notes:
[1] Permit Limit applied where more restrictive.

Notes: No 6 Fuel Oil–	18,300 Btu/lb	NOx= 67 lb/1000 gal	Bagasse – 8,000 Btu/lb (dry)	NOx= 0.235 lb/MMBtu
	8.2 lb/gal	CO = 5 lb/1000 gal	0.1% sulfur, max (dry)	CO = 29 lb/ton (wet)
	2.4 % sulfur	PM = 0.1 lb/MMBtu		PM = 0.15 , 0.2 or 0.3 lb/MMBtu

Table 4–25. Comparison of Existing Boiler and Cogen Facility Emissions, Osceola

	Existing Boilers*		Cogen Boilers (Biomass)	
Pollutant	lb/MMBtu	lb/1000 lb steam	lb/MMBtu	lb/1000 lb steam
SO2	0.125	0.24	0.10	0.15
NOx	0.16	0.31	0.116	0.174
PM	0.15	0.27	0.03	0.045
CO	3.625	5.66	0.35	0.526

* Lowest emission rate for any of the existing boilers.

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APPENDIX A

EMISSION FACTORS

Table A–1. Emission Factors for Criteria/Designated Pollutants, Osceola Power L. P. Cogeneration Facility

	Biomass		No. 2 Fuel		Coal	
Regulated Pollutant	Emission Factor (lb/MMBtu)	Reference	Emission Factor (lb/MMBtu)	Reference	Emission Factor (lb/MMBtu)	Reference
Particulate (TSP)	0.03	NSPS, Current permit limit	0.03	NSPS, Current permit limit	0.03	NSPS, Current permit limit
Particulate (PM10)	0.03	NSPS, Current permit limit	0.03	NSPS, Current permit limit	0.03	NSPS, Current permit limit
Sulfur dioxide: 24–hr	0.10	Current permit limit	0.05	Current permit limit	1.2	NSPS, Current permit limit
Annual average	0.02	Current permit limit				
Nitrogen oxides	0.116	SNCR system	0.12	Current permit limit	0.15	Current permit limit
Carbon monoxide	0.35	Current permit limit	0.20	Current permit limit	0.20	Current permit limit
VOC– Bagasse	0.060	Vendor information	0.03	Current permit limit	0.03	Current permit limit
Wood waste	0.040	Vendor information				
Lead	2.7E–06	Reference 1	8.9E–07	Current permit limit	5.1E–06	AP–42, Table 1.1–13, 99% eff.
Mercury– Bagasse	5.7E–06	Mercury control system	2.4E–06	Current permit limit	8.4E–06	Current permit limit
Wood waste	2.9E–07	Mercury control system				
Beryllium	– –		3.5E–07	Current permit limit	5.9E–06	Current permit limit
Fluorides	– –		6.27E–06	Current permit limit	0.024	Current permit limit
Sulfuric acid mist	0.00098	AP–42; 4% of SO2 is SO3	0.0025	AP–42; 4% of SO2 is SO3	0.010	AP–42; 4% of SO2 is SO3
Total reduced sulfur	– –		– –		– –	– –
Asbestos	– –		– –		– –	– –
Vinyl Chloride	– –		– –		– –	– –

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1. NCASI Technical Bulletin No. 650, June 1993.
2. Estimating Air Toxics Emissions From Oil and Coal Combustion Sources, EPA 450/2–89–001 (1989).
3. Emission Assessment of Conventional Stationary Combustion Systems: Volume V. EPA–600/7–81–0300c (1981).
4. Mercury Emissions to the Atmosphere in Florida, KBN Engineering and Applied Sciences, Inc. (1992).

Table A−2. Emission Factors for Hazardous Air Pollutants

	Biomass			No. 2 Fuel Oil			Coal		
	Ref.	Published Emission Factor	Converted Emission Factor (lb/MMBtu)	Ref.	Published Emission Factor	Converted Emission Factor (lb/MMBtu)	Ref.	Published Emission Factor	Converted Emission Factor (lb/MMBtu)
Acetaldehyde	1	7.8E−04 lb/MMBtu	7.8E−04						
Acetophenone	1	3.7E−06 lb/MMBtu	3.7E−06						
Acrolein	1	6.5E−05 lb/MMBtu	6.5E−05						
Antimony	1	ND	−−	3	24 lb/10^{12} Btu[a]	2.4E−07	5	0.15 ng/J	3.5E−05
Arsenic − Maximum	10	1.33E−04 lb/MMBtu	1.33E−04	8	4.2 lb/10^{12} Btu[a]	4.2E−08	9	542 lb/10^{12} Btu[a]	5.4E−06
− Annual	10	6.79E−05 lb/MMBtu	6.79E−05						
Benzene	1	1.3E−03 lb/MMBtu	1.3E−03						
Cadmium	1	0.84 lb/10^{12} Btu	8.4E−07	8	11 lb/10^{12} Btu[a]	1.1E−07	9	43 lb/10^{12} Btu[a]	4.3E−07
Carbon Disulfide	1	1.3E−04 lb/MMBtu	1.3E−04						
Carbon Tetrachloride	1	6E−06 lb/MMBtu	6.0E−06						
Chlorine	2	0.0078 lb/ton	9.2E−04						
Chloroform	1	4.7E−05 lb/MMBtu	4.7E−05						
Chromium − Maximum	10	1.58E−04 lb/MMBtu	1.58E−04	8	67 lb/10^{12} Btu[a]	6.7E−07	9	1570 lb/10^{12} Btu[a]	1.6E−05
− Annual	10	8.27E−05 lb/MMBtu	8.27E−05						
Chromium (VI) − Maximum	10	3.17E−05 lb/MMBtu	3.17E−05	7	20% of Cr	1.3E−07	7	20% of Cr	3.1E−06
− Annual	10	1.65E−05 lb/MMBtu	1.65E−05						
Cobalt	2	1.3E−04 lb/ton[a]	1.3E−04	5	50.5 pg/J	1.2E−05	5	0.31 ng/J	7.2E−05
Cumene	1	1.8E−05 lb/MMBtu	1.8E−05						
Di − n − Butyl Phthalate	1	5.8E−05 lb/MMBtu	5.8E−05						
Ethyl Benzene	1	3.9E−06 lb/MMBtu	3.9E−06						
Formaldehyde	1	1.3E−03 lb/MMBtu	1.3E−03	8	405 lb/10^{12} Btu	4.1E−04	9	221 lb/10^{12} Btu	2.2E−04
n Hexane	1	5.5E−04 lb/MMBtu	5.5E−04						
Hydrogen Chloride	1	5.6E−04 lb/MMBtu	5.6E−04	6	274 pg/J	6.4E−04	6	33.9 ng/J	7.9E−02
Manganese	1	95 lb/10^{12} Btu	9.5E−05	8	14 lb/10^{12} Btu[a]	1.4E−07	4	31 lb/10^{12} Btu[a]	3.1E−07
Methanol	1	1.5E−03 lb/MMBtu	1.5E−03						
Methyl Ethyl Ketone	1	1.2E−05 lb/MMBtu	1.2E−05						
Methyl Isobutyl Ketone	1	8.6E−04 lb/MMBtu	8.6E−04						
Methylene Chloride	1	1.5E−03 lb/MMBtu	1.5E−03						
Napthalene	1	5.9E−04 lb/MMBtu	5.9E−04						
Nickel	1	6.3 lb/10^{12} Btu	6.3E−06	8	170 lb/10^{12} Btu[a]	1.7E−06	4	1020 lb/10^{12} Btu[a]	1.0E−05
Phenols	1	4.1E−05 lb/MMBtu	4.1E−05						
Phosphorous	1	160 lb/10^{12} Btu	1.6E−06	5	25 pg/J	5.8E−05	5	3.7 ng/J	8.6E−04
Polycyclic Organic Matter	2	22 lb/10^{12} Btu	2.2E−07	8	8 lb/10^{12} Btu	8.4E−06			
Selenium	1	3.8 lb/10^{12} Btu	3.8E−06	2	38 lb/10^{12} Btu[a]	3.8E−07	5	0.23 ng/J	5.3E−05
Styrene	1	1.5E−05 lb/MMBtu	1.5E−05						
2,3,7,8 Tetrachlorodibenzo −p−dioxin	2	5.1E−11 lb/ton	6.0E−12						
Toluene	1	9.0E−05 lb/MMBtu	9.0E−05						
1,1,1 Trichlorethane	1	1.7E−04 lb/MMBtu	1.7E−04						
Trichloroethylene	1	7.6E−06 lb/MMBtu	7.6E−06						
m & p Xylene	1	7.8E−06 lb/MMBtu	7.8E−06						
o Xylene	1	2.6E−06 lb/MMBtu	2.6E−06						

---

[a] Uncontrolled emission factor; 99% control with ESP is assumed to calculate controlled emission factor.

Conversions:
lb/10^{12} Btu x 10^{12} Btu/1,000,000 MMBtu = lb/MMBtu
lb/ton x ton/2000 lb x lb/4250 BTU x 10^{6} Btu/MMBtu = lb/MMBtu
ng/J x 2.324x10^{-3} = lb/MMBtu (uncontrolled)
ng/J x 2.324x10^{-4} = lb/MMBtu (90% controll)
pg/J x 2.324x10^{-6} = lb/MMBtu (uncontrolled)
ng/J x 2.324x10^{-7} = lb/MMBtu (90% controll)

Note: UD = undetectable levels in gas stream.
References
1: Based on NCASI Compilation of Air Toxic Emission Data for Boilers, Pulp Mills, and Bleach Plants, Technical Bulletin No. 650, June 1993, Tables 5
2: AP−42, Tables 1.6−5 and 1.6−7.
3. AP−42, Table 1.3−11, low value for No. 6 fuel oil.
4: Estimating Emissions from Oil and Coal Combustion Sources EPA−450/2−89−001 (1989).
5: Emissions Assessment of Conventional Stationary Combustion Systems Volume V, 1981. Based on an uncontrolled spreader stoker design and then assuming 90% control from ESP.
6: Emissions Assessment of Conventional Stationary Combustion Systems Volume V, 1981. Based on an uncontrolled spreader stoker design.
7: Based upon stack test data at Dade County RRF, 1992, which indicated less than 20% of total chromium was chromium +6.
8. AP−42, Tables 1.3−9 and 1.3−11.
9. AP−42, Table 1.1−13.
10. Based on 2.4% treated wood burning.

Source: KBN, 1995.

Table A–3. Emission Factors for Florida Air Toxics

	Biomass			No.2 Fuel Oil			Coal		
	Ref.	Published Emission Factor	Converted Emission Factor (lb/MMBtu)	Reference	Published Emission Factor	Converted Emission Factor (lb/MMBtu)	Ref.	Published Emission Factor	Converted Emission Factor (lb/MMBtu)
Acetone	1	3.8E–04 lb/MMBtu							
Ammonia	2	1.50E–02 lb/MMBtu		2	1.50E–02 lb/MMBtu	1.50E–02	2	4.80E–02 lb/MMBtu	4.80E–02
Barium	3	0.0044 lb/ton[a]	5.20E–06	6	28.8 pg/J	6.69E–07	6	3.2 ng/J	7.44E–05
Benzo(a)anthracene	3	6.4E–06 lb/ton	7.53E–07						
Benzo(a)pyrene	3	3.0E–07 lb/ton	3.53E–08						
Bromine	3	0.00039 lb/ton	4.59E–05	6	3.0 pg/J	6.97E–07	6	0.34 ng/J	7.90E–05
Chrysene	3	3.0E–04 lb/ton	3.53E–05						
Copper – Maximum	4	1.25E–04 lb/MMBtu		7	4.20E–05 lb/MMBtu	4.20E–05	8	1.71E–04 lb/MMBtu	1.71E–04
Copper – Annual	4	8.02E–05 lb/MMBtu							
Indium	5	1.27E–04 lb/MMBtu							
Iodine	2	1.8E–05 lb/ton	2.12E–06						
Isopropanol	1	9.2E–03 lb/MMBtu							
Molybdenum	2	1.9E–04 lb/ton[a]	2.24E–07	6	21 pg/J	4.88E–07	6	0.38 ng/J	8.83E–06
PAH	1	5.9E–04 lb/MMBtu	5.90E–10						
Silver	1	140 lb/10^{12} Btu[a]	1.40E–06						
Thallium	1	ND							
Tin	2	3.1E–05 lb/ton[a]	3.65E–08	6	142 pg/J	3.3E–06	6	0.38 ng/J	8.83E–06
Tungsten	2	1.1E–05 lb/ton[a]	1.29E–08						
Vanadium	2	1.2E–04 lb/ton[a]	1.41E–07						
Yttrium	2	5.6E–05 lb/ton[a]	6.59E–08						
Zirconium	2	3.5E–04 lb/ton[a]	4.12E–07						

[a] Uncontrolled emission factor; 99% control with ESP is assumed to calculate controlled emission factor.

ND = Non–detectable

References

1. NCASI Technical Bulletin No. 650, June 1993.
2. Based on 25ppm NH3 in exhaust gases for biomass and No. 2 Fuel Oil; 65 ppm NH3 for coal.
3. AP–42, Tables 1.6–5 and 1.6–7.
4. Based on 2.4 % treated wood burning.
5. EPA PM/VOC Database updated October, 1989.
6. Emissions Assessment of Conventional Stationary Combustion Systems, Volume V, 1981. Based on uncontrolled spreader stoker design and then assuming 99% control from ESP if emitted as a particulate.
7. Toxic Air Pollutant Emission FActors – A Compilation for Selected Air Toxic Compounds and Sources, Second Edition EPA–450/2–90–011 (1990).
8. Estimating Emissions from Oil and Coal Combustion Sources EPA–450/2–89–001 (1989).

Conversions:

lb/10^{12} Btu x 10^{12} Btu/1,000,000 MMBtu = lb/MMBtu

lb/ton x ton/2000 lb x lb/4,250 BTU x 10^{6} Btu/MMBtu = lb/MMBtu

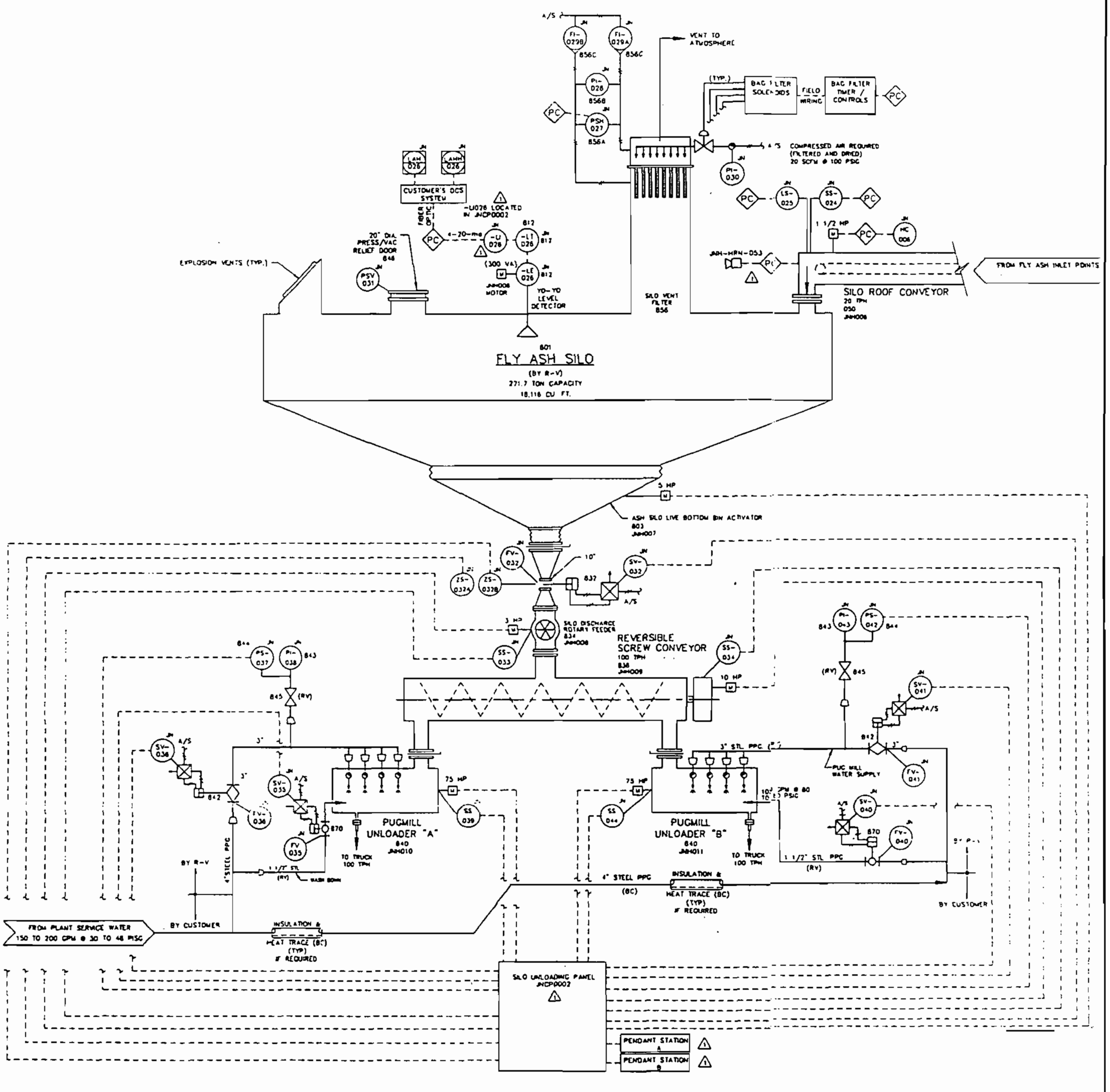
pg/J x 2.324x10^{-3} (lb/MMBtu)/(ng/J)x (1 – 0.99) = 2.324^{-5} lb/MMBtu

ng/J x 2.324x10^{-6} (lb/MMBtu)/(ng/J)x (1 – 0.99) = 2.324^{-8} lb/MMBtu

APPENDIX B

DRAWINGS

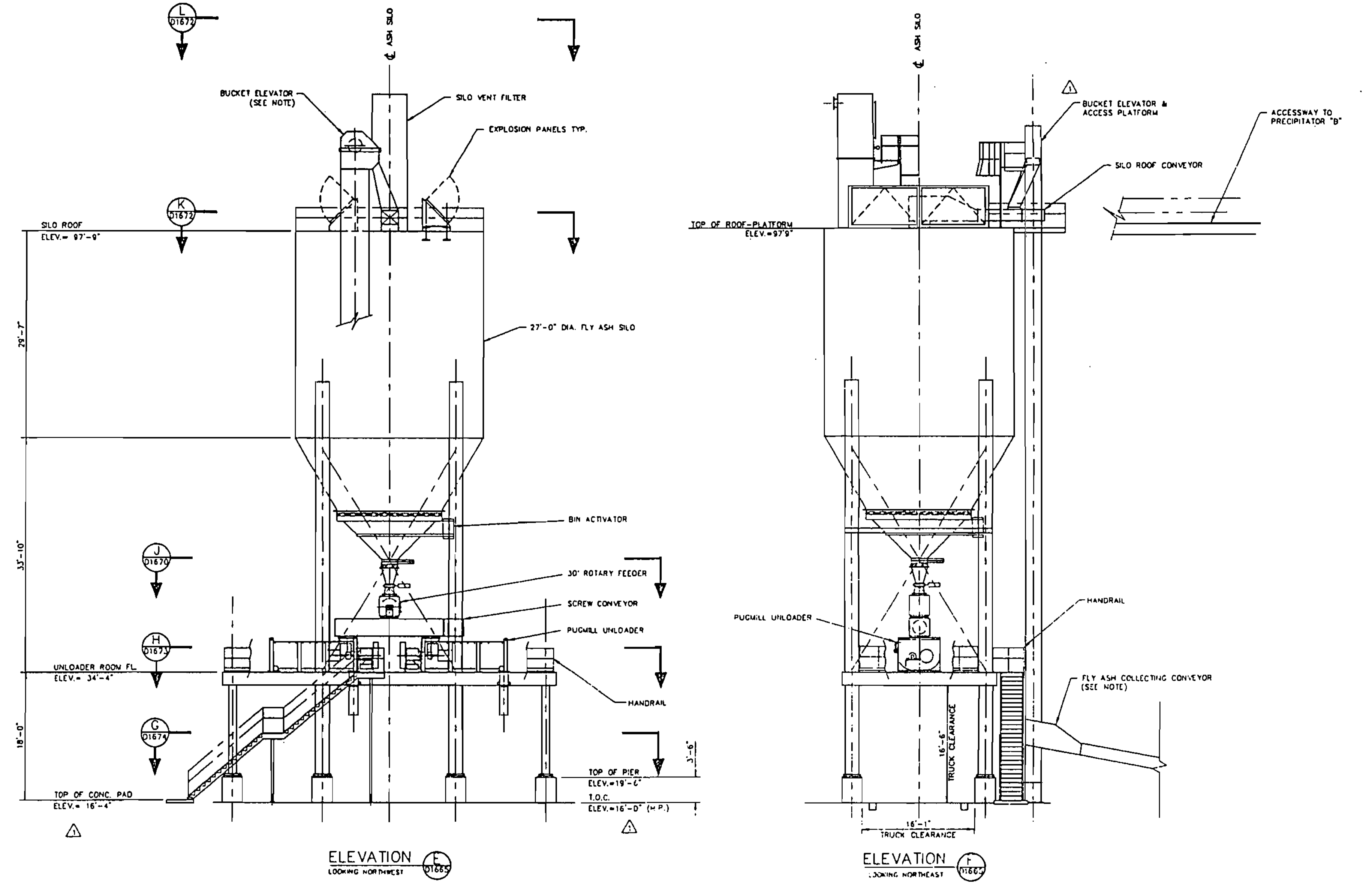
04-21-95



Fly Ash Silo

Source: RV Industries, Inc., 1994.

04-21-95



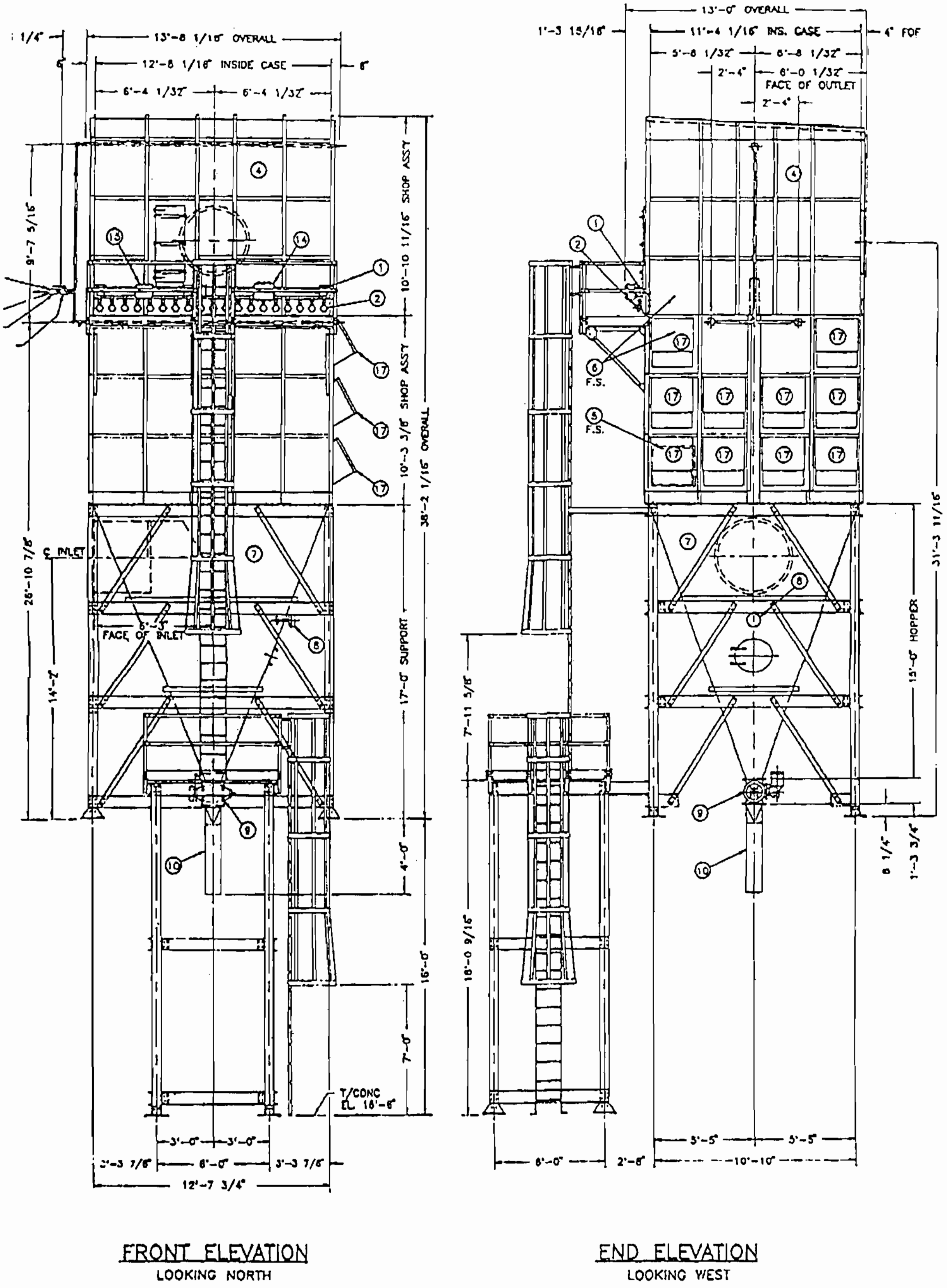
ELEVATION E D1665
LOOKING NORTHWEST

ELEVATION F D1665
LOOKING NORTHEAST

General Arrangement of Fly Ash System

Source: RV Industries, Inc., 1994.

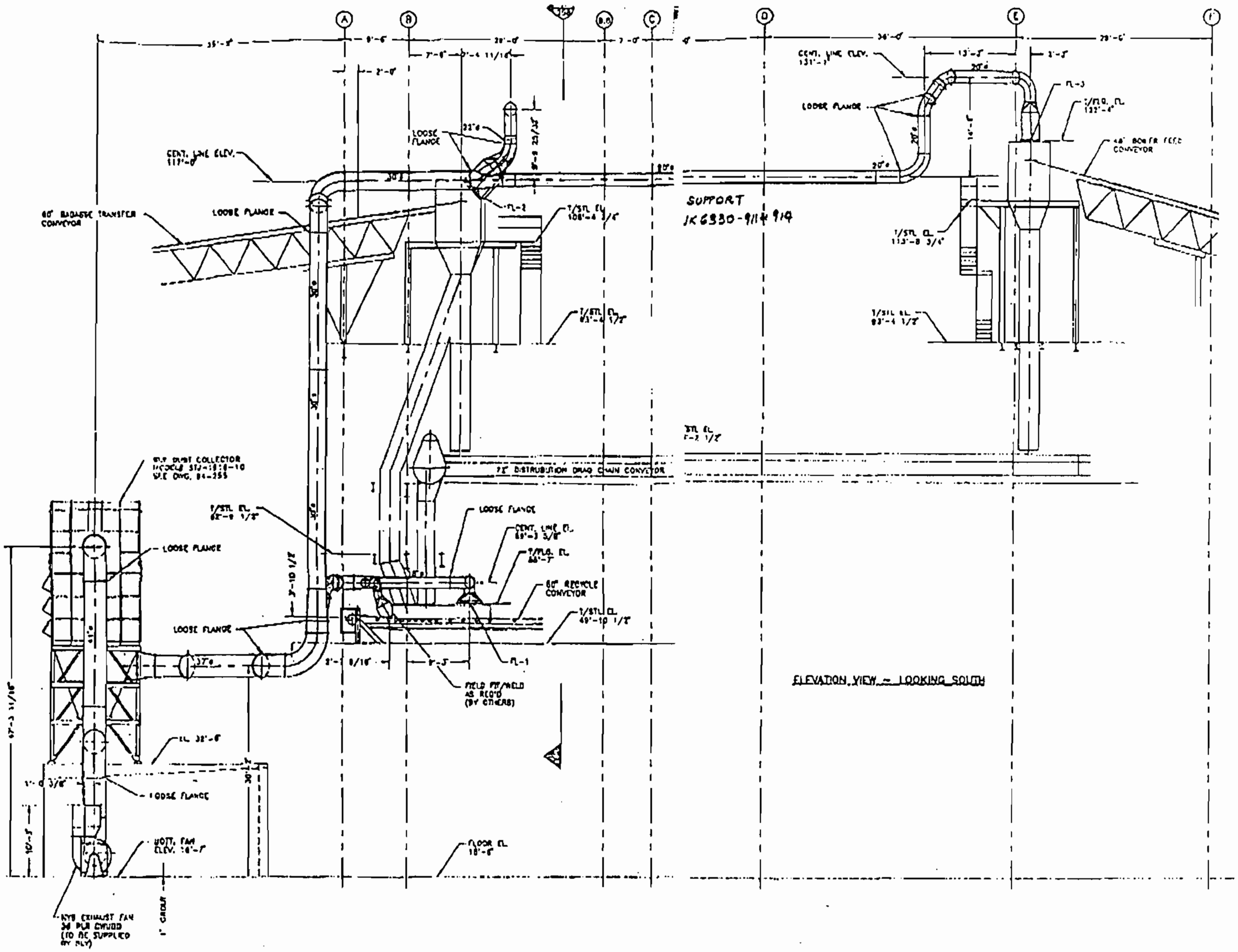
04-21-95



Elevation Views of Dust Collector at Boiler House

Source: Sly, Inc., 1994.

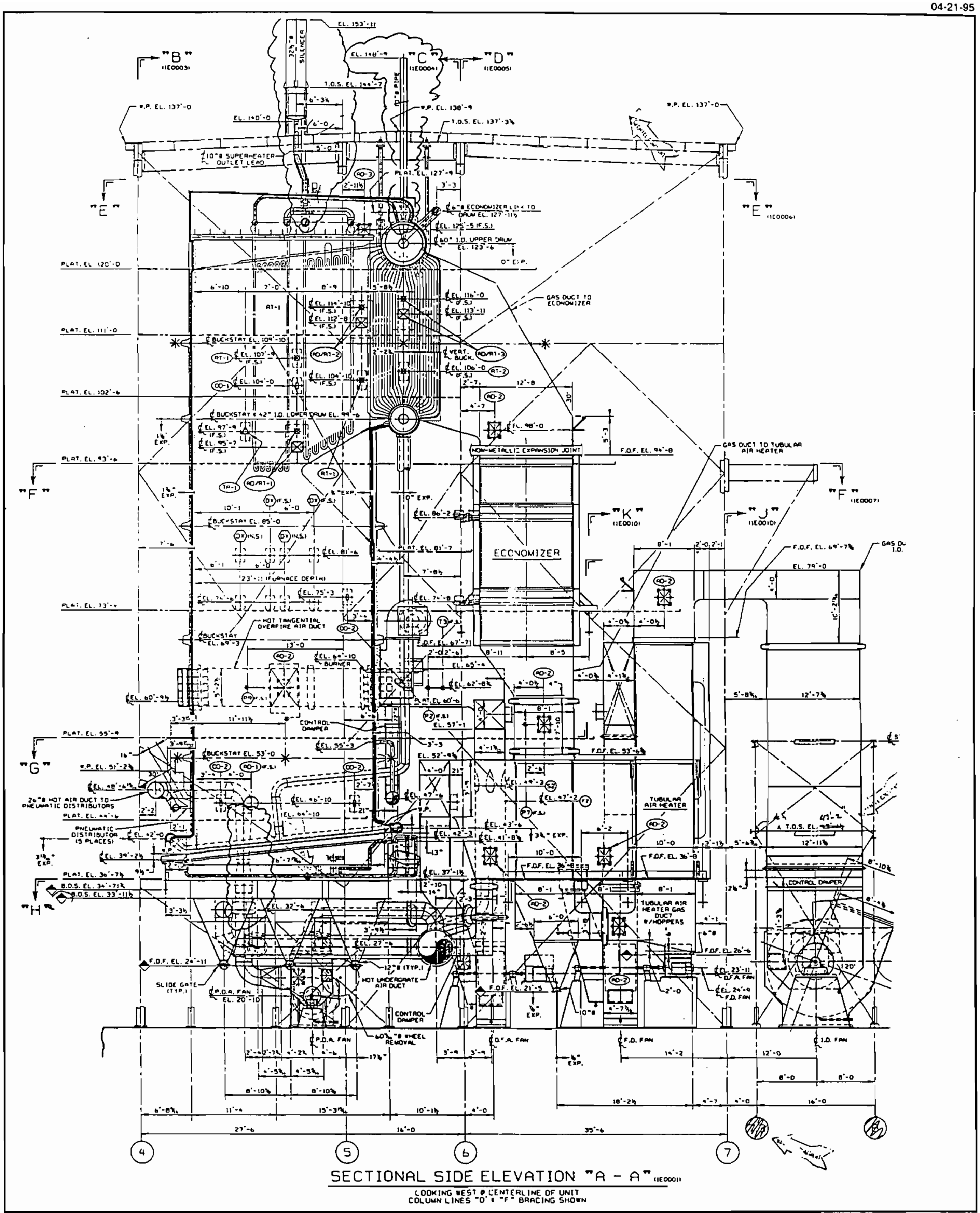
04-21-95



Schematic of Dust Collector at Boiler House

Source: Sly, Inc., 1994.

KBN



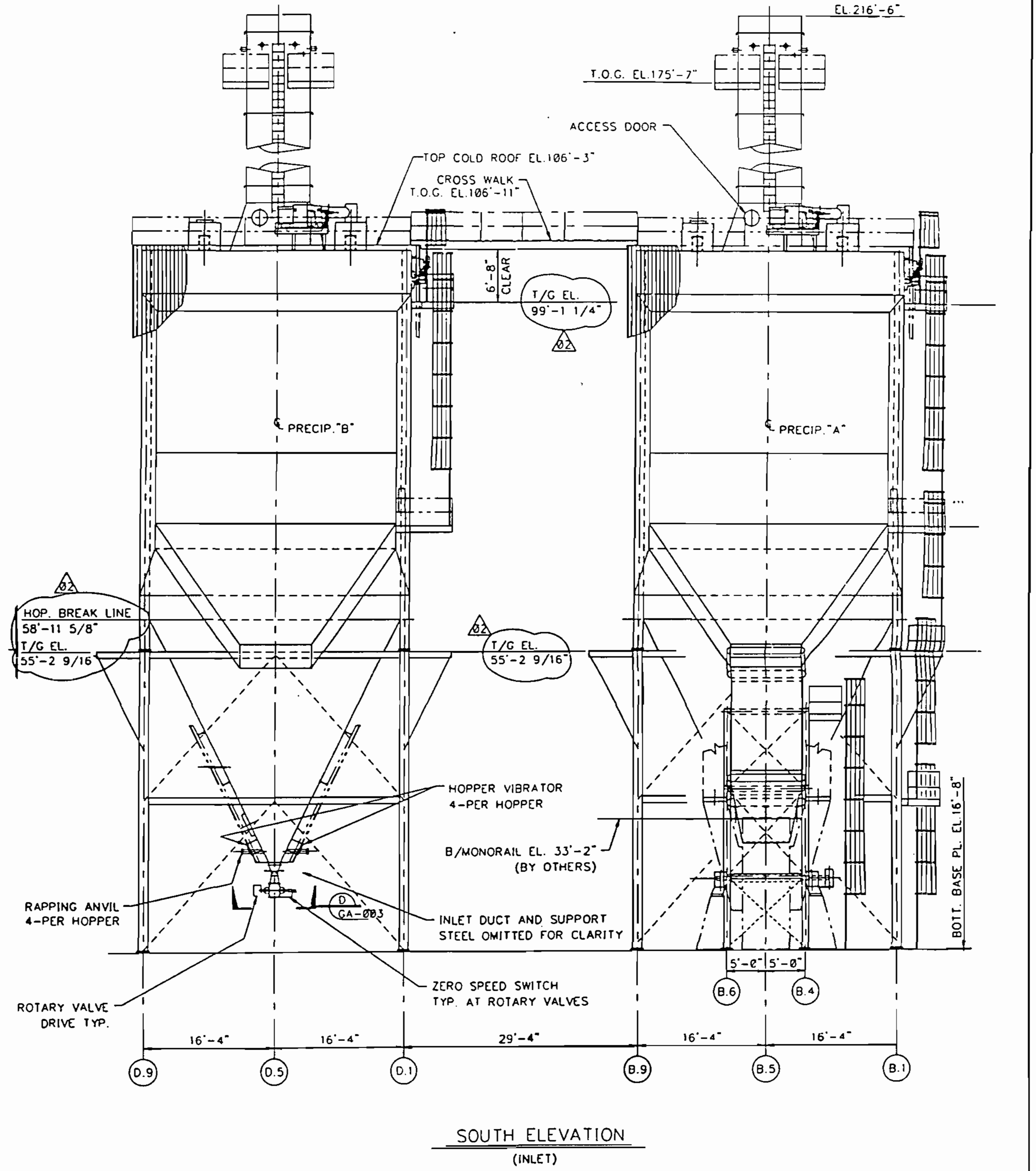
SECTIONAL SIDE ELEVATION "A - A" (1E0001)

LOOKING WEST @ CENTERLINE OF UNIT
COLUMN LINES "D" & "F" BRACING SHOWN

General Arrangement View of Boiler

Source: ABB Environmental Systems, 1994.

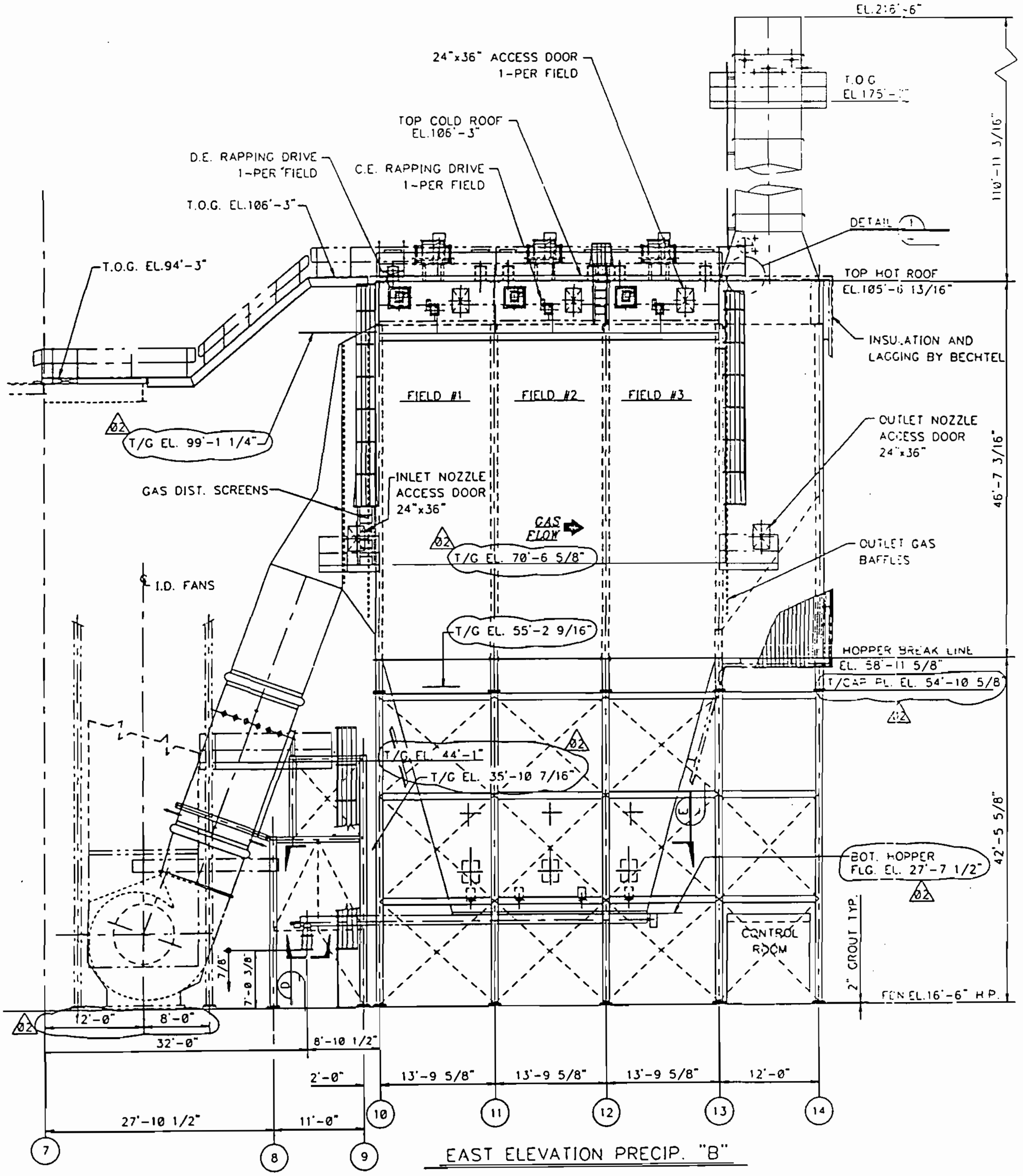
04-21-95



South Elevation of ESPs with Stack

Source: ABB Environmental Systems, 1994.

KBN

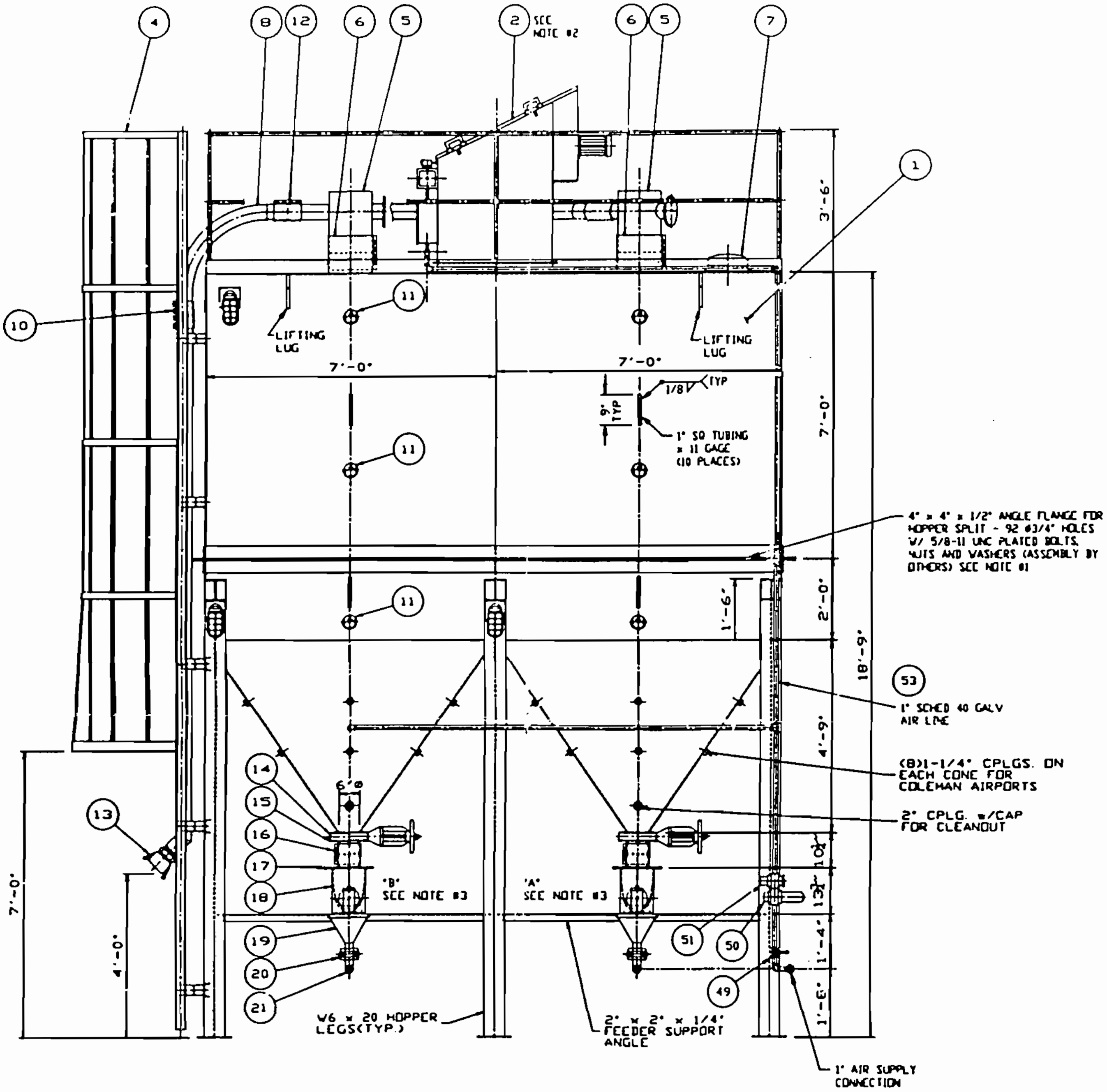


East Elevation of ESPs with Stack

Source: ABB Environmental Systems, 1994.

KBN

04-21-95

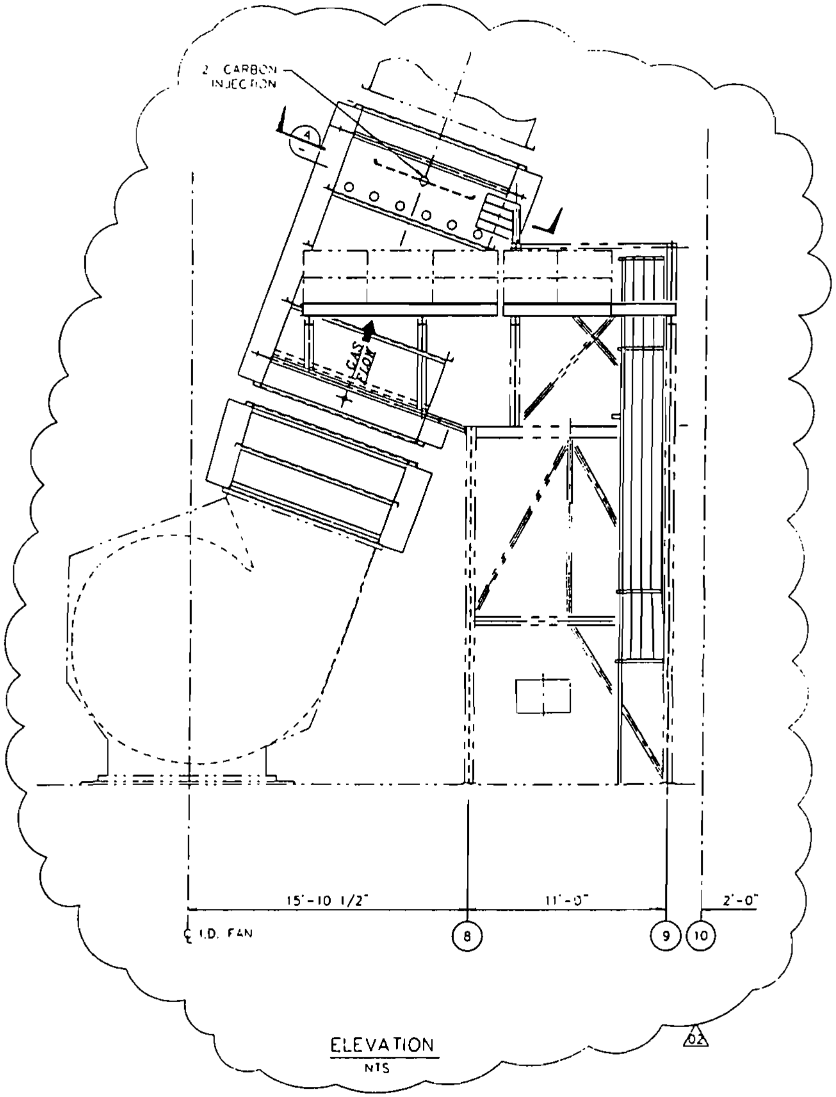


WEST ELEVATION

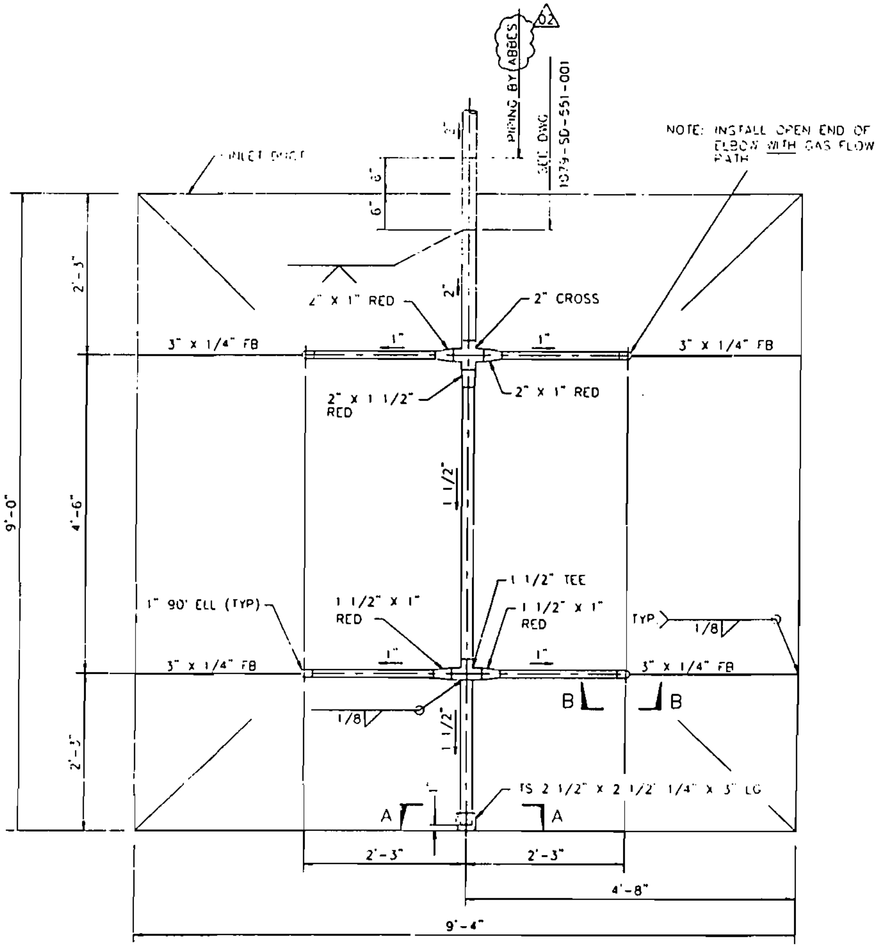
West Elevation of Carbon Storage Silos

Source: Chemco Equipment Co., 1994.

KBN



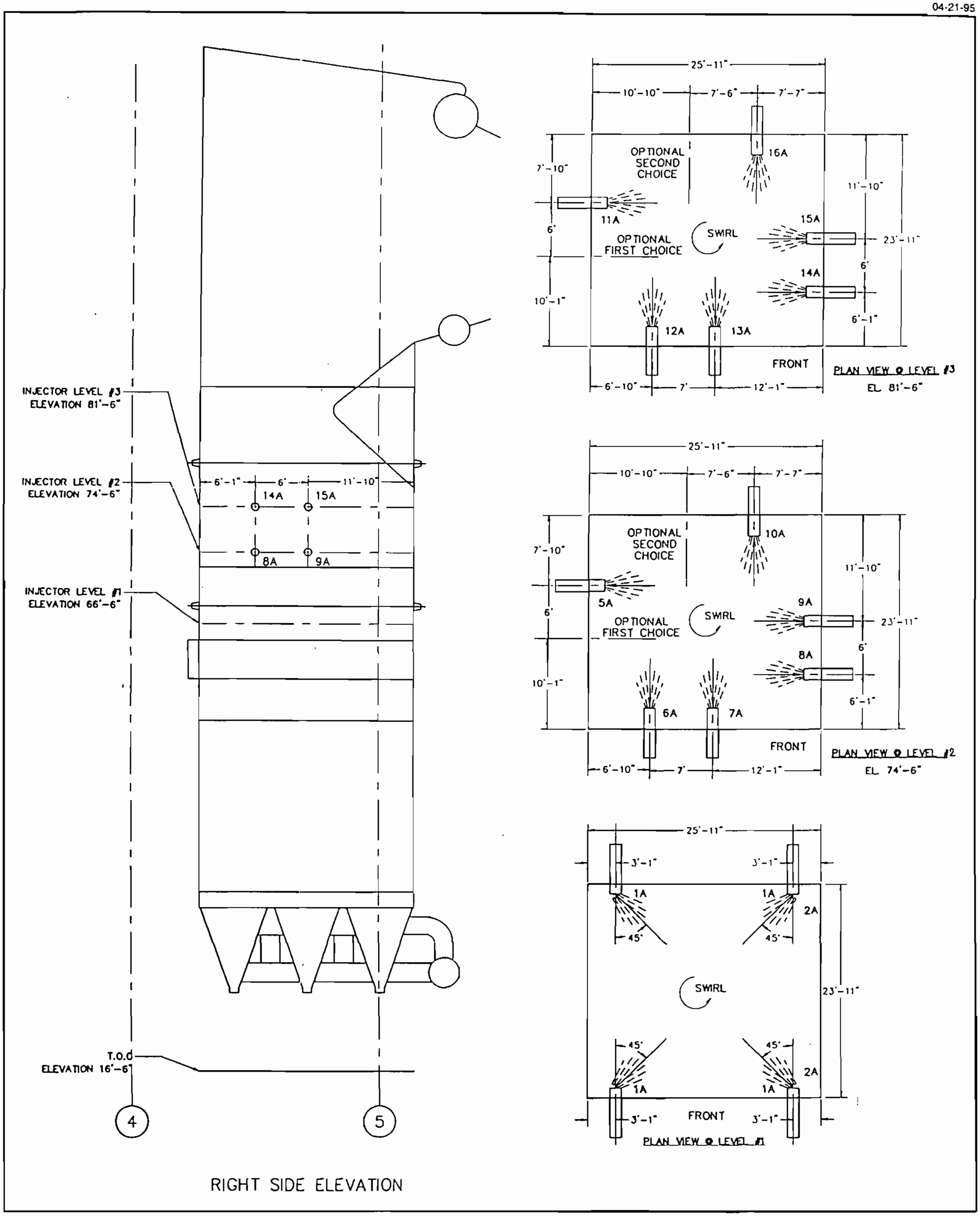
ELEVATION
NTS



SECTION A

Carbon Injection Configuration for Mercury Control

Source: ABB Environmental Systems, 1994.



Schematic of Urea Injection Points

Source: Nalco FuelTech, 1994.

KBN

APPENDIX C

FUGITIVE DUST CALCULATIONS

Table C1. Estimation of Emission Factors and Rates For Vehicle Traffic on Unpaved Roads Osceola Power Generation Facility

General Data	Pile Mainten. Front-end loader	Pile Mainten. Front-end loader
Vehicle Data		
Description	Bagasse	Coal
Vehicle Speed (S), mph- Average	5	5
Vehicle weight (W), tons- Loaded	27	27
- Unloaded	9	9
- Average	18	18
Vehicle number of wheels (w)	4	4
Vehicle miles traveled (VMT)- Annual	21,900 a	4,800 b
General/ Site Characteristics		
Days of precipitation greater than or equal to 0.01 inch (p)- Annual	120	120
Silt content (s), %	5	5
Particle size multiplier, PM (k)	1.00	1.00
Particle size multiplier, PM10 (k)	0.35	0.35
Emission Control Data		
Emission control method	Watering	Watering
Emission control removal efficiency, %	50	50
Calculated PM Emission Factor (EF)		
Uncontrolled EF, lb/VMT - Annual	0.96	0.96
Controlled (Final) EF,lb/VMT- Annual	0.48	0.48
Calculated PM10 Emission Factor (EF)		
Uncontrolled EF, lb/VMT - Annual	0.34	0.34
Controlled (Final) EF,lb/VMT- Annual	0.17	0.17
Estimated Emission Rate (ER)		
PM ER, lb/hr	2.41	2.41
TPY	5.278	1.157
PM10 ER, lb/hr	0.84	0.84
TPY	1.847	0.405

Emission Factor (EF) Equations

Uncontrolled EF (UEF) Equation: UEF(lb/VMT) = k x 5.9 x (s/12) x (S/30) x (W/3)^0.7 x (w/4)^0.5 x ((365 - p)/365)

Controlled (Final) EF (CEF) Equation: CEF(lb/VMT) = UEF (lb/ton) x (100 - Removal efficiency (%))

a Based on vehicle operating 12 hrs/day, 365 days/yr.

b Based on vehicle operating 8 hrs/day, 120 days/yr.

Source: AP-42, Section 13.2.1, Unpaved Roads, July, 1994.

```
                    Spreadsheet as of 11:52:07  on 03-28-1995

[illegible]ut Filename: coalpile.epc
Inventory area: Osceola Power L.P.
Source ID: Coalpile  Filename: A:\Coalpile.EPC

Emissions estimate year:     94
Based on wind data year:     94
Fastest mile filename:     westp94.met
System of units:     English
Source life (inclusive days of year)
     Start day: 1
       End day: 365
F=flat area, PC=conical pile, PO=oval pile:     PC
 Pile height ( ft) :30
 Pile diameter ( ft) :500
 Area (sq ft):      197658
Material description:     Coal
Percent moisture content:     4.5
Percent  silt content:     2.2
Threshold friction velocity, U*t, (cm/sec):     112
Roughness height (cm):     0.1
Mode (mm) of size distribution       3.533677#     (# denotes calculated value)
Lc value (cf. Fig. 6-3 of reference manual):


Frequency of disturbance information :
 [illegible]/Ur =  .9 -- subarea #  1      -- 50 % of regime disturbed every 4 day(s)
 [illegible]s/Ur =  .6 -- subarea #  1      -- 50 % of regime disturbed every 4 day(s)
 Us/Ur =  .2 -- subarea #  1      -- 50 % of regime disturbed every 4 day(s)



Total emissions emitted over the period:  95652.99 g


Threshold velocity =  112  cm/s
Control:  Effective windspeed ratio =  1

--------------------------------------------------
Us/Ur =  .9    Disturbance interval = 4  days

Period  9 - 13  high on  10   1.2069  m/s  1438.047  g emitted
Period  13 - 17  high on  16   1.12644  m/s  90.01624  g emitted
Period  33 - 37  high on  34   1.16667  m/s  712.3215  g emitted
Period  41 - 45  high on  45   1.32759  m/s  4235.759  g emitted
Period  45 - 49  high on  46   1.40805  m/s  6618.004  g emitted
Period  61 - 65  high on  62   1.85058  m/s  27114.97  g emitted
Period  65 - 69  high on  68   1.24713  m/s  2267.197  g emitted
Period  73 - 77  high on  77   1.16667  m/s  712.3215  g emitted
Period  77 - 81  high on  77   1.16667  m/s  712.3215  g emitted
Period  85 - 89  high on  88   1.12644  m/s  90.01624  g emitted
[illegible]iod  89 - 93  high on  93   1.24713  m/s  2267.197  g emitted
[illegible]od  93 - 97  high on  93   1.24713  m/s  2267.197  g emitted
Period  137 - 141  high on  141   1.24713  m/s  2267.197  g emitted
Period  141 - 145  high on  141   1.24713  m/s  2267.197  g emitted
Period  165 - 169  high on  168   1.16667  m/s  712.3215  g emitted
Period  189 - 193  high on  193   1.56897  m/s  12623.55  g emitted
```

```
Period  193 - 197  high on  193   1.56897  m/s  12623.55  g emitted
Period  205 - 209  high on  207   1.2069  m/s  1438.047  g emitted
Period  209 - 213  high on  212   1.32759  m/s  4235.759  g emitted
Period  321 - 325  high on  323   1.2069  m/s  1438.047  g emitted
Period  329 - 333  high on  333   1.12644  m/s  90.01624  g emitted
Period  333 - 337  high on  333   1.12644  m/s  90.01624  g emitted
Period  349 - 353  high on  353   1.16667  m/s  712.3215  g emitted
Period  353 - 357  high on  353   1.16667  m/s  712.3215  g emitted

Summary for Us/Ur =  .9      Disturbance Interval =  4
 87735.69  Total g emitted over  1  -  365
-------------------------------------------------------------------
Us/Ur =  .6    Disturbance interval = 4  days

Period  61 - 65  high on  62   1.23372  m/s  7917.303  g emitted

Summary for Us/Ur =  .6      Disturbance Interval =  4
 7917.303  Total g emitted over  1  -  365
-------------------------------------------------------------------
Us/Ur =  .2    Disturbance interval = 4  days


Summary for Us/Ur =  .2      Disturbance Interval =  4
 0  Total g emitted over  1  -  365
-------------------------------------------------------------------
Summary for entire source:  95652.99   g emitted over period  1  -  365
NOTE: For a variety of reasons given in the user manual, the erosion estimates
      presented above may be considered as CONSERVATIVELY HIGH.  See the
      user manual for more information.
```

```
                 Spreadsheet as of 11:57:11  on 03-28-1995

  ut Filename: bagpile.epc
Inventory area: Osceola Power L.P.
Source ID: Bagpile  Filename: A:\Bagpile.EPC

Emissions estimate year:      94
Based on wind data year:      94
Fastest mile filename:     westp94.met
System of units:     English
Source life (inclusive days of year)
     Start day: 1
       End day: 365
F=flat area, PC=conical pile, PO=oval pile:     PC
 Pile height ( ft) :30
 Pile diameter ( ft) :566
 Area (sq ft):      252888.5
Material description:     Bagasse/WW
Percent moisture content:     37
Percent  silt content:     2.2
Threshold friction velocity, U*t, (cm/sec):     112
Roughness height (cm):     0.3
Mode (mm) of size distribution      3.533677#     (# denotes calculated value)
Lc value (cf. Fig. 6-3 of reference manual):


Frequency of disturbance information :
   /Ur =  .9 -- subarea #  1      -- 20 % of regime disturbed every 1 day(s)
   /Ur =  .6 -- subarea #  1      -- 20 % of regime disturbed every 1 day(s)
 Us/Ur =  .2 -- subarea #  1      -- 20 % of regime disturbed every 1 day(s)



Total emissions emitted over the period:  79243.23 g


Threshold velocity =  112  cm/s
Control:  Effective windspeed ratio =  1

--------------------------------------------------
Us/Ur =  .9    Disturbance interval = 1  days

Period  9 - 10  high on  10   1.2069  m/s  735.9493  g emitted
Period  10 - 11  high on  10   1.2069  m/s  735.9493  g emitted
Period  15 - 16  high on  16   1.12644  m/s  46.0676  g emitted
Period  16 - 17  high on  16   1.12644  m/s  46.0676  g emitted
Period  33 - 34  high on  34   1.16667  m/s  364.5446  g emitted
Period  34 - 35  high on  34   1.16667  m/s  364.5446  g emitted
Period  44 - 45  high on  45   1.32759  m/s  2167.734  g emitted
Period  45 - 46  high on  46   1.40805  m/s  3386.895  g emitted
Period  46 - 47  high on  46   1.40805  m/s  3386.895  g emitted
Period  61 - 62  high on  62   1.85058  m/s  13876.62  g emitted
   iod  62 - 63  high on  62   1.85058  m/s  13876.62  g emitted
    od  67 - 68  high on  68   1.24713  m/s  1160.283  g emitted
Period  68 - 69  high on  68   1.24713  m/s  1160.283  g emitted
Period  76 - 77  high on  77   1.16667  m/s  364.5446  g emitted
Period  77 - 78  high on  77   1.16667  m/s  364.5446  g emitted
Period  87 - 88  high on  88   1.12644  m/s  46.0676  g emitted
```

```
Period  88 - 89   high on  88    1.12644  m/s  46.0676  g emitted
Period  92 - 93   high on  93    1.24713  m/s  1160.283  g emitted
Period  93 - 94   high on  93    1.24713  m/s  1160.283  g emitted
  riod  94 - 95   high on  94    1.16667  m/s  364.5446  g emitted
   iod  139 - 140  high on  140   1.2069  m/s  735.9493  g emitted
Period  140 - 141  high on  141   1.24713  m/s  1160.283  g emitted
Period  141 - 142  high on  141   1.24713  m/s  1160.283  g emitted
Period  142 - 143  high on  142   1.2069  m/s  735.9493  g emitted
Period  167 - 168  high on  168   1.16667  m/s  364.5446  g emitted
Period  168 - 169  high on  168   1.16667  m/s  364.5446  g emitted
Period  191 - 192  high on  192   1.2069  m/s  735.9493  g emitted
Period  192 - 193  high on  193   1.56897  m/s  6460.352  g emitted
Period  193 - 194  high on  193   1.56897  m/s  6460.352  g emitted
Period  206 - 207  high on  207   1.2069  m/s  735.9493  g emitted
Period  207 - 208  high on  207   1.2069  m/s  735.9493  g emitted
Period  211 - 212  high on  212   1.32759  m/s  2167.734  g emitted
Period  212 - 213  high on  212   1.32759  m/s  2167.734  g emitted
Period  322 - 323  high on  323   1.2069  m/s  735.9493  g emitted
Period  323 - 324  high on  323   1.2069  m/s  735.9493  g emitted
Period  332 - 333  high on  333   1.12644  m/s  46.0676  g emitted
Period  333 - 334  high on  333   1.12644  m/s  46.0676  g emitted
Period  352 - 353  high on  353   1.16667  m/s  364.5446  g emitted
Period  353 - 354  high on  353   1.16667  m/s  364.5446  g emitted
Period  354 - 355  high on  354   1.12644  m/s  46.0676  g emitted

Summary for Us/Ur =  .9      Disturbance Interval =  1
 71139.55  Total g emitted over  1  -  365
-----------------------------------------------------------------
Us/Ur =  .6    Disturbance interval = 1  days

   iod  61 - 62   high on  62    1.23372  m/s  4051.837  g emitted
Period  62 - 63   high on  62    1.23372  m/s  4051.837  g emitted

Summary for Us/Ur =  .6      Disturbance Interval =  1
 8103.673  Total g emitted over  1  -  365
-----------------------------------------------------------------
Us/Ur =  .2    Disturbance interval = 1  days


Summary for Us/Ur =  .2      Disturbance Interval =  1
 0  Total g emitted over  1  -  365
-----------------------------------------------------------------
Summary for entire source:  79243.23   g emitted over period  1  -  365
NOTE: For a variety of reasons given in the user manual, the erosion estimates
      presented above may be considered as CONSERVATIVELY HIGH.  See the
      user manual for more information.
```

APPENDIX D

TANKS PROGRAM OUTPUT

TANKS PROGRAM 2.0
EMISSIONS REPORT - DETAIL FORMAT
TANK IDENTIFICATION AND PHYSICAL CHARACTERISTICS

```
Identification
   Identification No.:        No. 2 Fuel
   City:                      Pahokee
   State:                     FL
   Company:                   Osceola Power
   Type of Tank:              Vertical Fixed Roof

Tank Dimensions
   Shell Height (ft):                 24
   Diameter (ft):                     20
   Liquid Height (ft):                20
   Avg. Liquid Height (ft):           18
   Volume (gallons):               50000
   Turnovers:                        280
   Net Throughput (gal/yr):     13992754

Paint Characteristics
   Shell Color/Shade:            White/White
   Shell Condition:              Good
   Roof Color/Shade:             White/White
   Roof Condition:               Good

Roof Characteristics
   Type:                         Dome
   Height (ft):                     0.17
   Radius (ft) (Dome Roof):        10.00
   Slope (ft/ft) (Cone Roof):     0.0000

Breather Vent Settings
   Vacuum Setting (psig):          -0.03
   Pressure Setting (psig):         0.03


Meteorological Data Used in Emission Calculations:  West Palm Beach, Florida
```

TANKS PROGRAM 2.0
EMISSIONS REPORT - DETAIL FORMAT
LIQUID CONTENTS OF STORAGE TANK

```
                                                            Liquid
                                       Daily Liquid Surf.   Bulk                            Vapor   Liquid  Vapor
                                       Temperatures (deg F) Temp.   Vapor Pressures (psia) Mol.    Mass    Mass    Mol.   Basis for Vapor Pressure
Mixture/Component               Month  Avg.   Min.   Max.   (deg F) Avg.    Min.    Max.    Weight  Fract.  Fract.  Weight Calculations
---------------------------------------------------------------------------------------------------------------------------------------------------------------------

Distillate fuel oil no. 2       All    76.54  71.86  81.22  74.62   0.0110  0.0095  0.0127  130.000                 130.00 Option 4: A=12.1010, B=8907.0
```

```
Annual Emission Calculations

Standing Losses (lb):                           11.1220
  Vapor Space Volume (cu ft):                   3979.35
  Vapor Density (lb/cu ft):                      0.0002
  Vapor Space Expansion Factor:                0.031045
  Vented Vapor Saturation Factor:              0.992671

Tank Vapor Space Volume
  Vapor Space Volume (cu ft):                   3979.35
  Tank Diameter (ft):                                20
  Vapor Space Outage (ft):                        12.67
  Tank Shell Height (ft):                            24
  Average Liquid Height (ft):                        18
  Roof Outage (ft):                                6.67

Roof Outage (Dome Roof)
  Roof Outage (ft):                                6.67
  Dome Radius (ft):                                  10
  Shell Radius (ft):                                 10

Vapor Density
  Vapor Density (lb/cu ft):                      0.0002
  Vapor Molecular Weight (lb/lb-mole):       130.000000
  Vapor Pressure at Daily Average Liquid
  Surface Temperature (psia):                  0.010998
  Daily Avg. Liquid Surface Temp.(deg. R):       536.21
  Daily Average Ambient Temp. (deg. R):          534.27
  Ideal Gas Constant R
    (psia cuft /(lb-mole-deg R)):                10.731
  Liquid Bulk Temperature (deg. R):              534.29
  Tank Paint Solar Absorptance (Shell):            0.17
  Tank Paint Solar Absorptance (Roof):             0.17
  Daily Total Solar Insolation
  Factor (Btu/sqftday):                        1438.00

Vapor Space Expansion Factor
  Vapor Space Expansion Factor:                0.031045
  Daily Vapor Temperature Range (deg.R):          18.72
  Daily Vapor Pressure Range (psia):           0.003196
  Breather Vent Press. Setting Range(psia):        0.06
  Vapor Pressure at Daily Average Liquid
  Surface Temperature (psia):                  0.010998
  Vapor Pressure at Daily Minimum Liquid
  Surface Temperature (psia):                  0.009502
  Vapor Pressure at Daily Maximum Liquid
  Surface Temperature (psia):                  0.012698
  Daily Avg. Liquid Surface Temp. (deg R):       536.21
  Daily Min. Liquid Surface Temp. (deg R):       531.53
  Daily Max. Liquid Surface Temp. (deg R):       540.89
  Daily Ambient Temp. Range (deg.R):              16.50
```

```
Annual Emission Calculations
Vented Vapor Saturation Factor
  Vented Vapor Saturation Factor:              0.992671
  Vapor Pressure at Daily Average Liquid
  Surface Temperature (psia):                  0.010998
  Vapor Space Outage (ft):                        12.67

Withdrawal Losses (lb):                        127.3954
  Vapor Molecular Weight (lb/lb-mole):       130.000000
  Vapor Pressure at Daily Average Liquid
  Surface Temperature (psia):                  0.010998
  Annual Net Throughput (gal/yr):              13992754
  Turnover Factor:                               0.2674
  Maximum Liquid Volume (cuft):                    6283
  Maximum Liquid Height (ft):                        20
  Tank Diameter (ft):                                20
  Working Loss Product Factor:                     1.00

Total Losses (lb):                               138.52
```

```
Annual Emissions Report

                                        Losses (lbs.):
Liquid Contents                         Standing    Withdrawal          Total
--------------------------------------------------------------------------
Distillate fuel oil no. 2                  11.12        127.40         138.52

Total:                                     11.12        127.40         138.52
```

APPENDIX E

DESCRIPTION OF MESOPUFF II MODELING ANALYSIS

SUPPLEMENTAL PSD CLASS I AREA ANALYSIS

INTRODUCTION

A long-range transport modeling analysis was performed in order to refine SO_2 impacts in the Everglades National Park (ENP) PSD Class I area. The long-range transport model MESOPUFF II (Version 94056) was used to address impacts from the proposed Osceola Power cogeneration facility.

The original protocol for this analysis was derived from a previous MESOPUFF II modeling protocol submitted to FDEP, EPA Region IV, and the National Park Service on behalf of Florida Power Corporation in March, 1992 (FPC, 1992a). A final approval for that protocol was granted in June 1992 (U.S. Department of Interior, 1992b). Some technical changes to that protocol have been made based on changes made in Version 94056, as documented in Model Change Bulletin No. 2. One major change was to allow a variable number of precipitation stations to be input. Previously, only one precipitation station could be input for each surface station input.

As discussed in Section 6.0, ambient air quality analyses have been performed to demonstrate compliance of the proposed project with AAQS and PSD Class II and I increments. The model selection and application for those analyses were based on recommendations in the U.S. Environmental Protection Agency (EPA) "Guideline on Air Quality Models (Revised)", 1990. The air dispersion model used in these analyses was the ISCST2 model, which is intended to predict impacts up to 50 kilometers (km) from a source. This model is referenced in Appendix A ("Appendix A" model) of the modeling guidelines, which means that the model may be used without justifying the use of technical methods and procedures provided the recommended regulatory options are selected. Because the proposed Osceola Power cogeneration facility is more than 100 km from the Class I area, the ISCST2 model is not appropriate for refining model impacts in the Class I area.

The modeling guideline does not specify a preferred model or protocol for long-range transport beyond 50 km. However, the above mentioned regulatory agencies have recommended the use of a long-range transport model, such as the MESOPUFF II model, to address impacts for such an application. Although the MESOPUFF II model is not an "Appendix A" model from the EPA modeling guidelines, it is referenced in Appendix B ("Appendix B" model) of the modeling guidelines and can be used on a case-by-case basis provided it can perform critical calculations or routines that are not available from an "Appendix A" model. In this case, the ISCST2 model, an "Appendix A" model, does not have the necessary dispersion and transport routines to adequately address long-range transport of plumes from emission sources. Since the proposed facility is more than 50 km from the critical receptors, the MESOPUFF II model is an appropriate method for addressing impacts at the ENP. The modeling methods and assumptions used in the MESOPUFF II model are presented in the following sections.

GENERAL DESCRIPTION OF MESOPUFF II MODEL

MESOPUFF II is a long-range transport model that is currently recommended by EPA for determining source impacts at distances greater than 50 km. Based on discussions with FDEP, EPA and NPS, this model can be used for the PSD Class I increment consumption analysis in support of air permit applications for emission sources located more than 50 km from a Class I area. The MESOPUFF II model has two preprocessor programs, READ62 and MESOPAC II, and one postprocessor program, MESOFILE II. The READ62 program is a preprocessor program to MESOPAC II (Version 94056), which is designed to read upper air (i.e., sounding) data obtained from the National Climatic Data Center (NCDC) in Asheville, North Carolina, and to reformat the data for use in the MESOPAC II program. The READ62 program also identifies missing data records. Missing data identified by READ62 must be filled in manually before input to the MESOPAC II program.

The MESOPAC II program is the meteorological preprocessor program for MESOPUFF II. The MESOPAC II program reads the upper air data file output from the READ62 program, as well as hourly surface meteorological data and hourly precipitation data collected at stations within the modeling area. Other data required for the MESOPUFF II model include land use and surface roughness lengths for each receptor grid point to be modeled.

The MESOPUFF II model provides concentration results for user-specified averaging times. The results can be processed by the MESOFILE II program to obtain additional statistical information about the concentrations produced from MESOPUFF II (e.g., annual average values). Postprocessor programs are used to produce highest, second-highest (HSH) short-term concentrations from MESOPUFF II model's output. The annual average and HSH concentrations for the 3- and 24-hour averaging period can be compared directly to allowable PSD Class I increments.

METEOROLOGICAL DATA

The general grid in which the meteorological data was prepared and processed consisted of a model domain that covered an area of 90,000 km^2, extending 300 km in the east-west and north-south directions. There are a total of 196 cells within the grid, with each cell covering a 400-km^2 area or 20 km in the east-west and north-south directions. The southwest corner of the model domain is located at UTM coordinates of 350,000 m, East, and 2,780,000 m, North in UTM Zone 17. The Class I area and emission sources are located within the grid and generally are 100 km or more from the grid's edges. The source, receptor and meteorological station locations within the MESOPUFF II coordinate system are presented in Table E-1.

The upper air data used in the analysis was read by the READ62 program to identify missing soundings and missing data for specific levels within a sounding. The program was modified to account for the data format changes that have occurred since the program originally was developed. The options selected for this program are presented in Table E-2.

Meteorological data for 1983 from the National Weather Service (NWS) stations located within or near the grid were used in the analysis. This year corresponds to the same year during which air dispersion modeling with the ISCST model indicated a 24-hour concentration in excess of 5.0 $\mu g/m^3$ in the Class I area. Upper air rawinsonde data for 1983 from the following upper air NWS stations were used:

1. Ruskin
2. West Palm Beach

These stations were selected because they are the nearest upper air stations to the study area. The data were reduced into 1-year records suitable for input to the READ62 program. Each station-year was run with the READ62 model to determine any missing data. The missing data was filled in by assuming data persistence from the previous valid observation (e.g., if data for the 12Z sounding are missing, the 00Z sounding from the previous day was used) or persistence from a lower level. Because the program expects data from the mandatory levels of 850, 700, and

Table E-1. MESOPUFF Model Source, Class I Receptor, and Meteorological Station Computational Grid Coordinates (Page 1 of 2)

			Computational Grid	
	UTM-East	UTM-North	X	Y
Sources:				
Sol-Energy Cogen	544.2	2968.0	10.71	11.40
Flo-Energy Cogen	525.0	2939.4	9.75	9.97
Dade Co Resource Recov.	564.3	2857.4	11.72	5.87
Tarmac	562.9	2861.7	11.65	6.08
FPL Lauderdale	580.1	2883.3	12.51	7.17
S. Broward Co RRF	579.6	2883.3	12.48	7.17
N. Broward Co RRF	583.6	2907.6	12.68	8.38
Lee County RRF	424.0	2946.0	4.70	10.30
Southern Gardens	487.6	2957.6	7.88	10.88
Bectel Indiantown	545.6	2991.5	10.78	12.58
FPL Martin	543.1	2992.9	10.66	12.64
Class I Receptors:				
1	557.0	2789.0	11.35	2.45
2	556.6	2792.0	11.33	2.60
3	556.0	2796.0	11.30	2.80
4	553.0	2796.5	11.15	2.83
5	548.0	2796.5	10.90	2.83
6	542.7	2796.5	10.64	2.83
7	542.7	2800.0	10.64	3.00
8	542.7	2805.0	10.64	3.25
9	542.7	2810.0	10.64	3.50
10	542.0	2811.0	10.60	3.55
11	541.3	2814.0	10.57	3.70
12	542.7	2816.0	10.64	3.80
13	544.1	2820.0	10.71	4.00
14	543.5	2824.6	10.68	4.23
15	545.0	2829.0	10.75	4.45
16	545.7	2832.2	10.79	4.61
17	546.2	2835.7	10.81	4.78
18	548.6	2837.5	10.93	4.88
19	550.3	2839.0	11.02	4.95
20	445.0	2839.0	5.75	4.95
21	440.0	2839.0	5.50	4.95
22	550.5	2844.0	11.03	5.20
23	545.0	2844.0	10.75	5.20
24	540.0	2844.0	10.50	5.20
25	550.3	2848.6	11.02	5.43
26	545.0	2848.6	10.75	5.43
27	540.0	2848.6	10.50	5.43
28	535.0	2848.6	10.25	5.43
29	530.0	2848.6	10.00	5.43
30	525.0	2848.6	9.75	5.43
31	520.0	2848.6	9.50	5.43

Table E-1. MESOPUFF Model Source, Class I Receptor, and Meteorological Station Computational Grid Coordinates (Page 2 of 2)

	UTM-East	UTM-North	Computational Grid X	Computational Grid Y
32	515.0	2848.6	9.25	5.43
33	515.0	2843.0	9.25	5.15
34	515.0	2838.0	9.25	4.90
35	515.0	2833.0	9.25	4.65
36	510.0	2833.0	9.00	4.65
37	505.0	2833.0	8.75	4.65
38	500.0	2833.0	8.50	4.65
39	495.0	2833.0	8.25	4.65
40	494.5	2837.0	8.23	4.85
41	491.5	2841.0	8.08	5.05
42	488.5	2845.5	7.93	5.28
43	483.0	2848.5	7.65	5.43
44	480.0	2852.5	7.50	5.63
45	475.0	2854.0	7.25	5.70
46	473.5	2857.0	7.18	5.85
47	473.5	2860.0	7.18	6.00
48	469.0	2860.0	6.95	6.00
49	464.0	2860.0	6.70	6.00
50	459.5	2864.0	6.48	6.20
51	454.0	2864.0	6.20	6.20
Meteorological Station:				
West Palm Beach	587.9	2951.5	12.895	10.573
Miami	573.5	2853.5	12.177	5.677
Fort Myers	413.7	2940.4	4.185	10.019
Ruskin	361.9	3064.5	1.597	16.227

Table E-2. Options Selected for READ56 Program- Osceola Power Cogeneration

Variable	Description	Selected Value
1. CARD 1 - STARTING AND ENDING HOURS, UPPER PRESSURE LEVEL		
IBYR, IBDAY, IBHR, IEYR, IEDAY, IEHR	Starting and ending year, day, hour	As needed
PSTOP	Top pressure level for which data are extracted	500 mb
2. CARD 2 - MISSING DATA CONTROL VARIABLES		
LHT	Height field control variable	True[a]
LTEMP	Height field control variable	True[a]
LWD	Wind direction field control variable	True[a]
LWS	Wind speed field control variable	True[a]

[a] Program run a second time with value set to false in order provide a missing value indicator for mandatory levels of 850, 700, and 500 mb. Data for these levels are input by user.

500 millibars (mb), data were inserted at these levels by persisting wind data from a lower level or temperature data for the same level from the previous sounding.

The MESOPAC II program was run to process the surface and upper air meteorological data for a format acceptable to the MESOPUFF II model. The options selected for this program are presented in Table E-3. The program was modified to account for the data format changes that have occurred since the program originally was developed. The surface meteorological data were obtained for the 5-year period of 1982 to 1986 from the following NWS stations, all located within the grid:

1. West Palm Beach
2. Miami and
3. Fort Myers

Hourly precipitation data were not utilized for any of the above surface meteorological stations. Land use data were developed for this grid from existing data developed by Argonne National Laboratory ("A Guide for Estimating Dry Deposition Velocities of Sulfur over the Eastern United States and Surrounding Regions, C.M. Sheih, et al., 1979). Since the model allows only a single land use type to be specified for each grid square, the land use category covering the greatest fraction of the total area within each grid square was selected.

MESOPUFF II MODELING APPROACH

The MESOPUFF II model was used to predict ambient concentrations at the same PSD Class I receptor location at which the ISCST2 predicted a refined 24-hour average concentration at or in excess of 5.0 $\mu g/m^3$. The model was run for the same meteorological periods identified by the ISCST2 model as causing the high concentrations (see Section 6.9.4). The options selected for the MESOPUFF II model are presented in Table E-4. Based on recommendations by the National Park Service and EPA, the distance to which the Turner dispersion parameters apply was 50 km (the model default distance is 100 km). After that distance, the dispersion parameters are based on time-dependent equations.

Emissions and stack parameters for the proposed Osceola Power cogeneration facility only were processed into the MESOPUFF II model input format. Concentrations were predicted at the same discrete receptors along the boundary of the ENP at which the high concentrations were

Table E-3. Options Selected for MESOPAC II Program- Osceola Power Cogeneration Facility (Page 1 of 2)

Variable	Description	Selected Value
1. CARD GROUP 1 - TITLE		
TITLE	Title of run	As needed
2. CARD GROUP 2 - GENERAL RUN INFORMATION		
NYR, IDYSTR, IHRMAX	Year, start day, and number	As needed
NSSTA, NUSTA, NPRSTA	Number of surface, precipitation, and rawinsonde stations	As needed
3. CARD GROUP 3 - GRID DATA		
IMAX, JMAX	Number of grid points in the X and Y directions	15, 15
DGRID	Grid spacing	20 km
4. CARD GROUP 4 - OUTPUT OPTIONS		
Various	Disk and printer control variables for writting data to disk	As needed
5. CARD GROUP 5 - LAND USE CATEGORIES AT EACH GRID POINT		
ILANDU	Land use categories at each grid point	15 by 15 array
6. CARD GROUP 6 - DEFAULT OVERRIDE OPTIONS		
IOPTS(1)	Surface wind speed mearurement heights control variable	0 (Default- 10 m)
IOPTS(2)	von Karman constant control variable	0 (Default)
IOPTS(3)	Friction velocity constants control variable	0 (Default)
IOPTS(4)	Mixing height constants control variable	0 (Default)
IOPTS(5)	Wind speed control variable	0 (Default - RADIUS = 99 km, ILWF = 2, IUWF = 4)

Table E-3. Options Selected for MESOPAC II Program- Osceola Power Cogeneration Facility (Page 2 of 2)

Variable	Description	Selected Value
IOPTS(6)	Surface roughness lengths control variable	0 (Default)
IOPTS(7)	Option to adjust heat flux estimate	0 (Default)
IOPTS(8)	Radiation reduction factors control variable	0 (Default)
IOPTS(9) variable	Heat flux constant control	0 (Default)
IOPTS(10)	Option to begin run at date other than at start of meteorological data files	0 or 1, as needed
7.- 14. CARD GROUPS 7 TO 14		
Various	Options input to override default values	Not used
15. CARD GROUP 15 - SURFACE STATION DATA		
Various	Surface meteorological station information	As needed
16. CARD GROUP 16 - RAWINSONDE STATION DATA		
Various	Rawinsonde meteorological station information	As needed
17. CARD GROUP 16 - PRECIPITATION STATION DATA		
Various	Precipitation meteorological station information	Not used

Note: Precipitation data were not used.

Table E-4. Options Selected for MESOPUFF II Program- Osceola Power Cogeneration Facility (Page 1 of 3)

Variable	Description	Selected Value
1. CARD GROUP 1 - TITLE		
TITLE	Title of run	As needed
2. CARD GROUP 2 - GENERAL RUN INFORMATION		
NSYR, NSDAY, NSHR	Year, start day and hour	As needed
NADVTS	Number of hours in run	As needed
NPTS	Number of point sources	As needed
NAREAS	Number of area sources	Not used
NREC	Number of non-gridded receptors	1 (Class I area)
NSPEC	Number of chemical species to model	1 (SO_2)
3. CARD GROUP 3 - COMPUTATIONAL VARIABLES		
IAVG	Concentration averaging time	24 hours
NPUF	Puff release rate for each source	1 puff/hour
NSAMAD	Minimum sampling rate	2 samples/hour
LVSAMP	Variable sampling rate option	True (increase rate with higher wind speeds)
WSAMP	Reference wind speed used in variable sampling rate option (used if LVSAMP is true)	2 m/s
LSGRID	Control variable for concentration computations at sampling grid points	False (sampling at non-gridded points only)
AGEMIN	Minimum age of puffs to be sampled	900 seconds (should not be larger than 3600 seconds)

Table E-4. Options Selected for MESOPUFF II Program- Osceola Power Cogeneration Facility (Page 2 of 3)

Variable	Description	Selected Value
4. CARD GROUP 4 - GRID INFORMATION		
Various	Numbers that define the beginning and end of the meteorological and computational grids	1,15
MESHDN	Sampling grid spacing factor	1
5. CARD GROUP 5 - TECHNICAL OPTIONS		
LGAUSS	Vertical concentration distribution option	True
LCHEM	Chemical transformation option	False[a]
LDRY	Dry deposition option	False[a]
LWET	Wet deposition option	False[a]
L3VL	Three vertical layer option	False[a]
6. CARD GROUP 6 - DEFAULT OVERRIDE OPTIONS		
Various	Disk and printer option to write data to disk	As needed
LPRINT	Printer output option (Print every IPRINT hours)	True
IPRINTF	Printing interval	24 hours
Various	Wet and dry deposition options	Not used
7. CARD GROUP 7 - DEFAULT OVERRIDE OPTIONS		
IOPTS(1)	Control variable for input of dispersion parameters	1 (see Card Group 8)
IOPTS(2)	Control variable for input of diffusivity constants	0 (Default)
IOPTS(3)	Control variable for input of SO_2 canopy resistance	0 (Default)
IOPTS(4)	Control variable for input	0 (Default)

Table E-4. Options Selected for MESOPUFF II Program- Osceola Power Cogeneration Facility (Page 3 of 3)

Variable	Description	Selected Value
	of dry deposition parameters	
IOPTS(5)	Control variable for input of wet removal parameters	0 (Default)
IOPTS(6)	Control variable for input of chemical transormation method	0 (Default)
8. CARD GROUP 8 - DISPERSION PARAMETERS		
AY, BY, AZ, BZ, AZT	Arrays of dispersion coefficients	Default
TMDEP	Distance beyond which the time-dependent equations are used for sigma y and z	50,000 m (Default is 100,000 m)
JSUP	Stability class used to determine growth rates for puffs above boundary layer	5 (Default)
9.- 13. CARD GROUPS 9 TO 13		
Various	Options input to override default values	Not used
14. CARD GROUP 14 - POINT SOURCE DATA		
Various	Point source information- location, stack and emission data	As needed
15. CARD GROUP 15 - AREA SOURCE DATA		
Various	Area source information- location, initial dispersion and emission data	Not used
16. CARD GROUP 16 - NON-GRIDDED RECEPTOR COORDINATES		
XREC, YREC	X- and Y-coordinates of non-gridded receptors	Used

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[a] This option was not used when the MESOPUFF II model was run in the inert mode. In the enhanced mode, this option was considered.

obtained. Predicted highest 24-hour SO_2 concentrations were obtained for at least three days prior and two days after the predicted days of the modeled high 24-hour concentrations.

Level 1

The predicted 24-hour concentrations from MESOPUFF for the proposed cogeneration facility were substituted into the ISCST2 model result and added to the predicted impacts produced for all other sources with the ISCST2 model. If the proposed source's impacts using MESOPUFF II model were less than the significant impact levels or the total predicted concentrations were less than the Class I increment, no additional modeling was required.

Level 2

If violations were predicted after the initial analysis, MESOPUFF II modeling was performed which involved using the results from Level 1 and performing additional modeling with the MESOPUFF II model for those sources located more than 50 km from the Class I area. These predicted concentrations were substituted for the ISCST2 model results. These MESOPUFF II model concentrations were added to those produced with the ISCST2 model for sources located at or within 50 km of the Class I area and MESOPUFF II model results from the proposed source to determine the total PSD Class I increment consumption. If the total predicted concentrations were less than the Class I increment, no additional modeling was required.

Level 3

These model runs incorporated the use of chemical transformation processes, wet and dry deposition, and vertical concentration distributions and is referred to as the **enhanced mode** of model operation.

MESOPUFF II MODEL RESULTS

A Level 1 modeling analysis was initially performed. A summary of the highest 24-hour SO_2 concentrations in the PSD Class I area predicted for 1983 using the ISCST2 model, and for which the proposed source's impact was greater than the significant impact level, are presented in Table E-5. The summary also contains the predicted concentration from Level 1 of the MESOPUFF II modeling. As shown, the results from Level 1 reduced the contribution from the proposed cogeneration facility from 1.13 $\mu g/m^3$ predicted with the ISCST2 model to 0.18 $\mu g/m^3$

Table E-5. Summary of 1983 Predicted High 24-Hour SO2 Concentration in the Class I Area Using the ISCST2 and MESOPUFF II Models

Time Period		Receptor	ISCST2 Concentrations (μg/m³)		MESOPUFF II Level 1 Concentration (μg/m³)		
Hour Ending	Calendar Date Month/Day	Receptor Number	All Sources	Proposed Osceola Power Facility	Proposed Osceola Power Facility	Adjusted Total	Is Increment Exceeded?
24	8/17	19	5.05	1.13	0.18	4.10	No

predicted with MESOPUFF II. The 0.18 $\mu g/m^3$ concentration was the maximum predicted for the HSH day processed. Based on these results, the ISCST2 model's predicted HSH value of 5.05 $\mu g/m^3$ reduces to 4.10 $\mu g/m^3$ which is in compliance with the 24-hour PSD Class I increment of 5.0 $\mu g/m^3$. Further Level 2 or 3 modeling analyses were therefore not performed for these periods.

APPENDIX F

SOURCE CONTRIBUTIONS TO MAXIMUM SO_2 CONCENTRATIONS

Table F-1. Source Contributions to Key ISCST2 Short-term AAQS and PSD Maximum Impacts

AAQS: 24-Hour

Total Modeled Concentration: 208.5 μg/m^3, at (270°, 6,600m), End Date 84121524.

U.S. Sugar Corp.-Bryant -	185.5	μg/m^3
Proposed Okeelanta -	21.6	
FPL - Riviera Beach	1.3	
West Palm Beach RRF -	0.1	

AAQS: 3-Hour

Total Modeled Concentration: 1,059.1 μg/m^3, at (272°, 6,200m), End Date 82070515.

Proposed Okeelanta -	30.7	μg/m^3
FPL - Riviera Beach -	7.1	
U.S. Sugar Corp.-Bryant -	1,020.8	
Palm Beach County RRF -	0.5	

PSD Class II: 24-Hour

Total Modeled Concentration: 76.4 μg/m^3 at (232°, 1,600 m), End Date 85100824

Proposed Okeelanta -	23.7	μg/m^3
U.S. Sugar Corp.-Bryant -	52.2	
Palm Beach County RRF -	0.5	

PSD Class II: 3-Hour

Total Modeled Concentration: 190.7 μg/m^3, at (276°, 6,200 m), End Date 86051215.

U.S. Sugar Corp.-Bryant -	190.7	μg/m^3

PSD Class I: 3-Hour

Total Modeled Concentration: 22.8 μg/m^3, at (497000,2830500), End Date 82071621).

Proposed Osceola	7.3	μg/m^3
Proposed Okeelanta	1.3	
Bechtel Indiantown	1.1	
FPL-Martin	13.1	