Rayonier

Performance Fibers

Fernandina Mill

August 30, 2005

Mr. Christopher Kirts, P. E.
Air Program District Administrator
7825 Baymeadows Way, Suite B-200
Jacksonville, FL 32256-7590

RE: Title V Permit No.
Construction Permit
Number 6 Power Boiler Construction

Dear Mr. Kirts:

Attached is a permit application for the installation of a replacement boiler at Rayonier Performance Fibers LLC's Fernandina Beach Dissolving Sulfite Pulp Mill and an unrelated production increase. This is a rather straightforward application in that the new boiler is replacing three older boilers with much less stringent emission standards. The new boiler will have four Continuous Emission Monitors, for NO_x, SO_2, flow and Opacity, along with oxygen and carbon monoxide monitors for better process control. The old boilers have no Continuous Emission Monitors and only oxygen process monitors. Once the new boiler is installed the old boilers will be decommissioned and eventually dismantled.

As discussed with you and your staff this application covers both the boiler and increasing the production limit placed on the permit in 1998 at the time No. 6 digester was installed. These projects are entirely separate. They are only combined here for ease of permitting. Indeed, the two projects are completely separate. The old boilers need to be replaced because they are unreliable and require frequent repair. The old boilers are, however, capable of producing enough steam in conjunction with the recovery boiler to produce the additional product which is the subject of the second project included in this application. Because the new boiler is not necessary to manufacture this additional product, the production increase is completely separate from the new boiler installation. In fact, the production increase is merely the removal of an artificial limit taken to avoid PSD when #6 digester was added in order to facilitate inspection and repair of the existing digesters.

The boiler permit alone does not trigger PSD permitting. The production increase does not trigger PSD permitting. Any increase in emissions is less than the PSD Significance Level. The power boiler project increases NO_x and SO_2 emissions to less than significant levels and decreases PM, VOC and carbon monoxide emissions. The Production increase project increases SO_2 and CO emissions and due to emission reductions in the bleach plant VOC emissions will decrease at the final production rate.

The replacement boiler in this application is actually a used boiler, constructed in 1983, before promulgation of NSPS Subpart Db. A Reconstruction Analysis is provided to demonstrate that this boiler will not undergo reconstruction and therefore retains its status as an existing boiler. The applicable NSPS for this boiler is Subpart D. Because it is not reconstructed the boiler remains an existing source under boiler MACT. It will clearly meet boiler MACT upon startup. It will start up about the deadline for Boiler MACT compliance deadline of September 17, 2007.

The new boiler will be more efficient and reliable and will reduce the consumption of #6 oil in favor of wood waste. The Production Increase Project is a modest increase in production to make full use of the No. 6 digester added in 1998 to avoid production loss during the extensive inspection and maintenance undertaken by the industry on all existing digesters subsequent to the catastrophic loss of a digester at a Florida mill. Because No. 6 digester was added by accepting a production limit in 1998, the PSD analysis had to be done as if the digester had never been constructed. This analysis has been done beginning with 2003-2004 emissions because emission estimates prior to this date would not include reductions mandated by 40 CFR Part 63. The analysis starts with the baseline used in 1998 No. 6 digester permit of 149,957 ADMT/yr (air dried metric tons per year). An increase in the production limit from 153,205 to 175,000 ADMT/year is proposed. Few pieces of the new equipment needed to achieve this rate have emissions. Some additional drying and cooling cans at the machine, and additional washers in the bleach plant. Nanofiltration of the HCE liquor which will free up sufficient evaporator capacity for the additional red liquor produced, and capture of waste heat will also capture VOC emissions at the bleach plant. This project is entirely separate from the boiler project. The mill has sufficient steam capacity with existing boilers to achieve this production.

Since this boiler already exists and engineering work is proceeding quickly we could start moving and working on the boiler and preparing foundations in the October - November 2005 period. This application seems rather straightforward. Your prompt action on it would be appreciated. To expedite timing, this application is only for the Construction Permit leaving the longer lead-time Title V Permit Application to be submitted after issuance of the Construction Permit.

If you have questions regarding this application please contact either Dick Hopper, (904)277-1480, email: dick.hopper@rayonier.com or Dave Tudor (904)277-1452, email: david.tudor@rayonier.com.

Sincerely,

F. J. Perrett

F. J. Perrett
General Manager

APPLICATION TABLE OF CONTENTS

Department of Environmental Protection

Division of Air Resource Management

APPLICATION FOR AIR PERMIT - LONG FORM

RECEIVED
SEP 15 2005
BUREAU OF AIR REGULATION

I. APPLICATION INFORMATION

Air Construction Permit – Use this form to apply for an air construction permit for a proposed project:

- subject to prevention of significant deterioration (PSD) review, nonattainment area (NAA) new source review, or maximum achievable control technology (MACT) review; or
- where the applicant proposes to assume a restriction on the potential emissions of one or more pollutants to escape a federal program requirement such as PSD review, NAA new source review, Title V, or MACT; or
- at an existing federally enforceable state air operation permit (FESOP) or Title V permitted facility.

Air Operation Permit – Use this form to apply for:

- an initial federally enforceable state air operation permit (FESOP); or
- an initial/revised/renewal Title V air operation permit.

Air Construction Permit & Revised/Renewal Title V Air Operation Permit (Concurrent Processing Option) – Use this form to apply for both an air construction permit and a revised or renewal Title V air operation permit incorporating the proposed project.

To ensure accuracy, please see form instructions.

Identification of Facility

1. Facility Owner/Company Name: **Rayonier Performance Fibers LLC**	
2. Site Name: **Fernandina Beach Dissolving Sulfite Pulp Mill**	
3. Facility Identification Number: 0890004	
4. Facility Location... Street Address or Other Locator: **Foot of Gum Street** City: **Fernandina Beach** County: **Nassau** Zip Code: **32034**	
5. Relocatable Facility? ☐ Yes ☒ No	6. Existing Title V Permitted Facility? ☒ Yes ☐ No

Application Contact

1. Application Contact Name: **David E. Tudor**
2. Application Contact Mailing Address... Organization/Firm: **Rayonier Inc.** Street Address: **Post Office Box 2002** City: **Fernandina Beach** State: **FL** Zip Code: **32035**
3. Application Contact Telephone Numbers... Telephone: **(904) 277 - 1452** ext. Fax: **(904) 277 - 1411**
4. Application Contact Email Address: **david.tudor@rayonier.com**

Application Processing Information (DEP Use)

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

APPLICATION INFORMATION

Purpose of Application

This application for air permit is submitted to obtain: (Check one)

Air Construction Permit

[X] Air construction permit.

Air Operation Permit

[ ] Initial Title V air operation permit.

[ ] Title V air operation permit revision.

[ ] Title V air operation permit renewal.

[ ] Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is required.

[ ] Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is not required.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit (Concurrent Processing)

[ ] Air construction permit and Title V permit revision, incorporating the proposed project.

[ ] Air construction permit and Title V permit renewal, incorporating the proposed project.

Note: By checking one of the above two boxes, you, the applicant, are requesting concurrent processing pursuant to Rule 62-213.405, F.A.C. In such case, you must also check the following box:

[ ] I hereby request that the department waive the processing time requirements of the air construction permit to accommodate the processing time frames of the Title V air operation permit.

Application Comment

A Title V Permit Amendment Application will follow issuance of the Construction Permit. Construction is planned to begin in late November 2005.

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Proc. Fee
PB06	**Bubbling Bed 450 mmBtu/hr boiler**	**AC**	**NA**

Application Processing Fee

Check one: ☐ Attached - Amount: $____________ ☒ Not Applicable

APPLICATION INFORMATION

Owner/Authorized Representative Statement

Complete if applying for an air construction permit or an initial FESOP.

1.	Owner/Authorized Representative Name : **F. J. Perrett**
2.	Owner/Authorized Representative Mailing Address... Organization/Firm: **Rayonier Performance Fibers LLC** Street Address: **Post Office Box 2002** City: **Fernandina Beach** State: **FL** Zip Code: **32035**
3.	Owner/Authorized Representative Telephone Numbers... Telephone: **(904)277-1405_** ext. Fax: **(904)277-1411**
4.	Owner/Authorized Representative Email Address: **jack.perrett@rayonier.com**
5.	Owner/Authorized Representative Statement: *I, the undersigned, am the owner or authorized representative of the facility addressed in this air permit application. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof and all other requirements identified in this application to which the facility is subject. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department, and I will promptly notify the department upon sale or legal transfer of the facility or any permitted emissions unit.* Fred J Perrett 8/30/05 Signature Date

APPLICATION INFORMATION

Application Responsible Official Certification
Complete if applying for an initial/revised/renewal Title V permit or concurrent processing of an air construction permit and a revised/renewal Title V permit. If there are multiple responsible officials, the "application responsible official" need not be the "primary responsible official."

1. Application Responsible Official Name:

2. Application Responsible Official Qualification (Check one or more of the following options, as applicable):

- [ ] For a corporation, the president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit under Chapter 62-213, F.A.C.
- [ ] For a partnership or sole proprietorship, a general partner or the proprietor, respectively.
- [ ] For a municipality, county, state, federal, or other public agency, either a principal executive officer or ranking elected official.
- [ ] The designated representative at an Acid Rain source.

3. Application Responsible Official Mailing Address...
Organization/Firm:
Street Address:
City: State: Zip Code:

4. Application Responsible Official Telephone Numbers...
Telephone: ( ) - ext. Fax: ( ) -

5. Application Responsible Official Email Address:

6. Application Responsible Official Certification:

I, the undersigned, am a responsible official of the Title V source addressed in this air permit application. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof and all other applicable requirements identified in this application to which the Title V source is subject. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department, and I will promptly notify the department upon sale or legal transfer of the facility or any permitted emissions unit. Finally, I certify that the facility and each emissions unit are in compliance with all applicable requirements to which they are subject, except as identified in compliance plan(s) submitted with this application.

____________________ _______________
Signature Date

APPLICATION INFORMATION

Professional Engineer Certification

1.	Professional Engineer Name: **David A. Buff** Registration Number: **19011**
2.	Professional Engineer Mailing Address... Organization/Firm: **Golder Associates Inc.** Street Address: **6241 N.W. 23rd Street, Suite 500** City: **Gainesville** State: **FL** Zip Code: **32653**
3.	Professional Engineer Telephone Numbers... Telephone: **(325)336-5600** ext. **545** Fax: **(352)336-6603**
4.	Professional Engineer Email Address: **dbuff@golder.com**
5.	Professional Engineer Statement:

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

(1) To the best of my knowledge, there is reasonable assurance that the air pollutant emissions unit(s) and the air pollution control equipment described in this application for air permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; and

(2) To the best of my knowledge, any emission estimates reported or relied on in this application are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of hazardous air pollutants not regulated for an emissions unit addressed in this application, based solely upon the materials, information and calculations submitted with this application.

(3) If the purpose of this application is to obtain a Title V air operation permit (check here [ ], if so), I further certify that each emissions unit described in this application for air permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance plan and schedule is submitted with this application.

(4) If the purpose of this application is to obtain an air construction permit (check here [X], if so) or concurrently process and obtain an air construction permit and a Title V air operation permit revision or renewal for one or more proposed new or modified emissions units (check here [ ], if so), I further certify that the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.

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

David A. Buff ____ 9/7/05 ____
Signature Date

(seal)

* Attach any exception to certification statement.

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates... Zone **14** East (km) **454.7** North (km) **3392.2**		2. Facility Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)	
3. Governmental Facility Code: **NA**	4. Facility Status Code: **A**	5. Facility Major Group SIC Code: **26**	6. Facility SIC(s): **2611**
7. Facility Comment :			

Facility Contact

1. Facility Contact Name: **Richard Hopper**
2. Facility Contact Mailing Address... Organization/Firm: **Rayonier Performance Fibers LLC** Street Address: **Post Office Box 2002** City: **Fernandina Beach** State: **FL** Zip Code: **32035**
3. Facility Contact Telephone Numbers: Telephone: (**904)277-1480** ext. Fax: **(904)277-**
4. Facility Contact Email Address: dick.hopper@rayonier.com

Facility Primary Responsible Official

Complete if an "application responsible official" is identified in Section I. that is not the facility "primary responsible official."

1. Facility Primary Responsible Official Name:
2. Facility Primary Responsible Official Mailing Address... Organization/Firm: Street Address: City: State: Zip Code:
3. Facility Primary Responsible Official Telephone Numbers... Telephone: ( ) - ext. Fax: ( ) -
4. Facility Primary Responsible Official Email Address:

FACILITY INFORMATION

Facility Regulatory Classifications

Check all that would apply *following* completion of all projects and implementation of all other changes proposed in this application for air permit. Refer to instructions to distinguish between a "major source" and a "synthetic minor source."

1. ☐ Small Business Stationary Source	☐ Unknown
2. ☐ Synthetic Non-Title V Source	
3. ☒ Title V Source	
4. ☒ Major Source of Air Pollutants, Other than Hazardous Air Pollutants (HAPs)	
5. ☐ Synthetic Minor Source of Air Pollutants, Other than HAPs	
6. ☒ Major Source of Hazardous Air Pollutants (HAPs)	
7. ☐ Synthetic Minor Source of HAPs	
8. ☐ One or More Emissions Units Subject to NSPS (40 CFR Part 60)	
9. ☐ One or More Emissions Units Subject to Emission Guidelines (40 CFR Part 60)	
10. ☒ One or More Emissions Units Subject to NESHAP (40 CFR Part 61 or Part 63)	
11. ☐ Title V Source Solely by EPA Designation (40 CFR 70.3(a)(5))	
12. Facility Regulatory Classifications Comment:	

FACILITY INFORMATION

List of Pollutants Emitted by Facility

1. Pollutant Emitted	2. Pollutant Classification	3. Emissions Cap [Y or N]?
See Attachment 3		

B. EMISSIONS CAPS

Facility-Wide or Multi-Unit Emissions Caps

1. Pollutant Subject to Emissions Cap	2.Facility Wide Cap [Y or N]? (all units)	3. Emissions Unit ID No.s Under Cap (if not all units)	4.Hourly Cap (lb/hr)	5.Annual Cap (ton/yr)	6. Basis for Emissions Cap

7. Facility-Wide or Multi-Unit Emissions Cap Comment:

There are no Facility-wide caps proposed in the application.

C. FACILITY ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Facility Plot Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) [X] Attached, Document ID: **Attachment 1** [ ] Previously Submitted, Date:
2. Process Flow Diagram(s): (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) [X] Attached, Document ID: **Attachment 2** [ ] Previously Submitted, Date:______
3. Precautions to Prevent Emissions of Unconfined Particulate Matter: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) [ ] Attached, Document ID:__________ [x] Previously Submitted, Date: **11/6/2002**

Additional Requirements for Air Construction Permit Applications

1. Area Map Showing Facility Location: [X] Attached, Document ID: **Attachment 4** [ ] Not Applicable (existing permitted facility)
2. Description of Proposed Construction or Modification: [X] Attached, Document ID: **Attachment 5**
3. Rule Applicability Analysis: [X] Attached, Document ID: **Attachment 5**__
4. List of Exempt Emissions Units (Rule 62-210.300(3)(a) or (b)1., F.A.C.): [ ] Attached, Document ID:________ [X] Not Applicable (no exempt units at facility)
5. Fugitive Emissions Identification (Rule 62-212.400(2), F.A.C.): [ ] Attached, Document ID:________ [x] Not Applicable
6. Preconstruction Air Quality Monitoring and Analysis (Rule 62-212.400(5)(f), F.A.C.): [ ] Attached, Document ID:_________ [X] Not Applicable
7. Ambient Impact Analysis (Rule 62-212.400(5)(d), F.A.C.): [ ] Attached, Document ID:_________ [X] Not Applicable
8. Air Quality Impact since 1977 (Rule 62-212.400(5)(h)5., F.A.C.): [ ] Attached, Document ID:_________ [X] Not Applicable
9. Additional Impact Analyses (Rules 62-212.400(5)(e)1. and 62-212.500(4)(e), F.A.C.): [ ] Attached, Document ID:_________ [X] Not Applicable
10. Alternative Analysis Requirement (Rule 62-212.500(4)(g), F.A.C.): [ ] Attached, Document ID:_________ [X] Not Applicable

FACILITY INFORMATION

Additional Requirements for FESOP Applications

1. List of Exempt Emissions Units (Rule 62-210.300(3)(a) or (b)1., F.A.C.): ☐ Attached, Document ID:________ ☒ Not Applicable (no exempt units at facility)

Additional Requirements for Title V Air Operation Permit Applications

1. List of Insignificant Activities (Required for initial/renewal applications only): ☐ Attached, Document ID:________ ☒ Not Applicable (revision application)
2. Identification of Applicable Requirements (Required for initial/renewal applications, and for revision applications if this information would be changed as a result of the revision being sought): ☐ Attached, Document ID:________ ☒ Not Applicable (revision application with no change in applicable requirements)
3. Compliance Report and Plan (Required for all initial/revision/renewal applications): ☐ Attached, Document ID:________ Note: A compliance plan must be submitted for each emissions unit that is not in compliance with all applicable requirements at the time of application and/or at any time during application processing. The department must be notified of any changes in compliance status during application processing.
4. List of Equipment/Activities Regulated under Title VI (If applicable, required for initial/renewal applications only): ☐ Attached, Document ID:________ ☐ Equipment/Activities On site but Not Required to be Individually Listed ☒ Not Applicable
5. Verification of Risk Management Plan Submission to EPA (If applicable, required for initial/renewal applications only) : ☐ Attached, Document ID:________ ☒ Not Applicable
6. Requested Changes to Current Title V Air Operation Permit: ☐ Attached, Document ID:________ ☒ Not Applicable

Additional Requirements Comment

Since this is not a Title V or a PSD permit application, Preconstruction Monitoring, Ambient Impact, Air Quality Impact and Additional Impact analyses are not required by regulation. All pollutants but NO_x and SO_2 decrease. NO_x and SO_2 increase less than the PSD significance level of 40 tons per year for each pollutant. The NO_x Ambient Air Quality Standard is only expressed on a annual average. The new boiler stack height is taller than the existing stacks being replaced. Thus there is no reason to expect such analyses would predict air quality violations. There are no fugitive emissions associated with either project included in this application. Bark, knots and wood chips are wet and not subject to dusting. Only fresh wood chips made onsite are pneumatically conveyed. It was shown in the 1995 Title V permit application that chips contain only minute amounts of suspendable material.

III. EMISSIONS UNIT INFORMATION - PB06

Title V Air Operation Permit Application - For Title V air operation permitting only, emissions units are classified as regulated, unregulated, or insignificant. If this is an application for Title V air operation permit, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each regulated and unregulated emissions unit addressed in this application for air permit. Some of the subsections comprising the Emissions Unit Information Section of the form are optional for unregulated emissions units. Each such subsection is appropriately marked. Insignificant emissions units are required to be listed at Section II, Subsection C.

Air Construction Permit or FESOP Application - For air construction permitting or federally enforceable state air operation permitting, emissions units are classified as either subject to air permitting or exempt from air permitting. The concept of an "unregulated emissions unit" does not apply. If this is an application for air construction permit or FESOP, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air permitting are required to be listed at Section II, Subsection C.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit Application – Where this application is used to apply for both an air construction permit and a revised/renewal Title V air operation permit, each emissions unit is classified as either subject to air permitting or exempt from air permitting for air construction permitting purposes and as regulated, unregulated, or insignificant for Title V air operation permitting purposes. **The air construction permitting classification must be used to complete the Emissions Unit Information Section of this application for air permit.** A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air construction permitting and insignificant emissions units are required to be listed at Section II, Subsection C.

If submitting the application form in hard copy, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application must be indicated in the space provided at the top of each page.

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

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

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

Emissions Unit Description and Status

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

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

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

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

2. Description of Emissions Unit Addressed in this Section: **This emission unit is a fluidized bed boiler burning a variety of fuels but mostly waste wood and bark. The boiler was constructed in 1983 and has not been reconstructed in this conversion.**

3. Emissions Unit Identification Number: **PB06**

4. Emissions Unit Status Code: **C**	5. Commence Construction Date: **11/2005**	6. Initial Startup Date: **11/2006**	7. Emissions Unit Major Group SIC Code: **2611**	8. Acid Rain Unit? [ ] Yes [X] No

9. Package Unit: **NA**
Manufacturer: Model Number:

10. Generator Nameplate Rating: **NA** MW

11. Emissions Unit Comment:

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description: **The particulate emissions from this boiler are controlled by a large settling chamber followed by a large ESP capable of achieving 0.07 lb/mmBtu PM emissions. Sulfur dioxide emissions are controlled by an alkaline scrubber. The boiler will rely mostly on staged combustion, flue gas recirculation and boiler design to achieve the NO_x limits. Should it be necessary to lower NO_x emissions to achieve the annual Cap the boiler is designed to receive an SNCR system.**	
2.	Control Device or Method Code(s):**005,010, 129, 204. 025, 026, possibly 032**

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate: **NA**		
2. Maximum Production Rate: **NA**		
3. Maximum Heat Input Rate: **525** million Btu/hr **See comment below.**		
4. Maximum Incineration Rate: **NA** pounds/hr	tons/day	
5. Requested Maximum Operating Schedule:	**24** hours/day	**7** days/week
	52 weeks/year	**8760** hours/year
6. Operating Capacity/Schedule Comment: **Maximum Heat Input Rate Comment: The annual average operating rate will not exceed 450 mmBtu/h. However, a maximum heat input rate of 525 mmBtu/hr will be needed for periods when the only other boiler at the facility is down.**		

C. EMISSION POINT (STACK/VENT) INFORMATION
(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: **PB06**	2. Emission Point Type Code: **1**

3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:
This is a single bubbling fluidized bed power boiler burning mostly biomass to produce steam for electrical generation and manufacturing process use. The emission exhaust through a single stack.

4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:
PB06

5. Discharge Type Code: **V**	6. Stack Height: feet **190 above ground**	7. Exit Diameter: feet **10**
8. Exit Temperature: **150** °F	9. Actual Volumetric Flow Rate: **183,421** acfm	10. Water Vapor: **21.3** %

11. Maximum Dry Standard Flow Rate: **144,352** dscfm	12. Nonstack Emission Point Height: feet **NA**
13. Emission Point UTM Coordinates... Zone: East (km): North (km):	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) **30/39/30** Longitude (DD/MM/SS) **81/28/40**

15. Emission Point Comment:

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1_ of 4_

1. Segment Description (Process/Fuel Type): **This fuel segment is for green bark at about 50% moisture.**		
2. Source Classification Code (SCC): **10100901**	3. SCC Units: **tons burned**	
4. Maximum Hourly Rate: **52**	5. Maximum Annual Rate: **451,425**	6. Estimated Annual Activity Factor: **NA**
7. Maximum % Sulfur: **0.03**	8. Maximum % Ash: **2.27**	9. Million Btu per SCC Unit: **9**
10. Segment Comment: **Approximately 60% is self produced as a byproduct.**		

Segment Description and Rate: Segment **2** of **4**

1. Segment Description (Process/Fuel Type): **This fuel segment is for knots and sidehill fines recovered as process byproduct at about 50% - 60% moisture.**		
2. Source Classification Code (SCC): **10100901**	3. SCC Units: **tons burned**	
4. Maximum Hourly Rate: **5.3**	5. Maximum Annual Rate: **46,269**	6. Estimated Annual Activity Factor: **NA**
7. Maximum % Sulfur: **0.40**	8. Maximum % Ash: **0.41**	9. Million Btu per SCC Unit: **9**
10. Segment Comment: **100% of this fuel is produced as a pulping byproduct.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION (CONTINUED)

Segment Description and Rate: Segment **3** of **4**

1. Segment Description (Process/Fuel Type): **This segment is for Tire Derived Fuel.**		
2. Source Classification Code (SCC): **10100801**	3. SCC Units: **tons burned**	
4. Maximum Hourly Rate: **3.0**	5. Maximum Annual Rate: **26,159**	6. Estimated Annual Activity Factor: **NA**
7. Maximum % Sulfur: **1.85**	8. Maximum % Ash: **4.78**	9. Million Btu per SCC Unit: **31**
10. Segment Comment:		

Segment Description and Rate: Segment **4** of **4**

1. Segment Description (Process/Fuel Type): **This segment is for No. 6 oil.**		
2. Source Classification Code (SCC): **10100401**	3. SCC Units: **thousand gallons burned**	
4. Maximum Hourly Rate: **1.4**	5. Maximum Annual Rate: **11,927**	6. Estimated Annual Activity Factor: **NA**
7. Maximum % Sulfur: **2.5**	8. Maximum % Ash: **0.12**	9. Million Btu per SCC Unit: **150**
10. Segment Comment: **This segment includes small amounts of self-generated on-spec used oil.**		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM	005	010	EL
PM10	010		EL
SO2	129		EL
NO_x	025	026	EL
CO	204		NS
Pb	010		NS

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –

POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control: **99.9% +**
3.Potential Emissions: **36.75** lb/hour **137.97** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): **NA** to tons/year	
6. Emission Factor: **0.07 lb/mmBtu** Reference: **40 CFR 63.7500 Table**	7. Emissions Method Code: **0**
8. Calculation of Emissions: **hrly: 525 mmBtu/hr x 0.07 lb/mmBtu = 36.75 lbs/hr** **ann: 450 mmBtu/hr x 0.07 lb/mmBtu x 1/2000 tons/lbs x 8760 hr/year = 137.97 TPY**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -

ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions **1** of **3**

1. Basis for Allowable Emissions Code: **RULE 62-296.410(2)(b)(2)**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.2 lb/mmBTU**	4. Equivalent Allowable Emissions: **105** lb/hour **394.2** tons/year

5. Method of Compliance:
Settling Chamber followed by Electrostatic Precipitator

6. Allowable Emissions Comment (Description of Operating Method):
Normal operating mode this boiler will burn mostly bark and knots.
0.2 lb/mmBtu x 450 mmBtu/hr x 8760/2000 = 394.2 TPY
0.2 lb/mmBtu x 525 mmBtu/hr = 105.0 lb/hr

Allowable Emissions Allowable Emissions **2** of **3**

1. Basis for Allowable Emissions Code: **RULE 40 CFR 60.42**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.1 lb/mmBtu**	4. Equivalent Allowable Emissions: **52.5** lb/hour **197.1** tons/year

5. Method of Compliance:
Settling Chamber followed by Electrostatic Precipitator

6. Allowable Emissions Comment (Description of Operating Method):
0.1 lb/mmBtu x 450 mmBtu/hr x 8760/2000 = 197.1 TPY
0.1 lb/mmBtu x 525 mmBtu/hr = 52.5 lb/hr

Allowable Emissions Allowable Emissions **3** of **3**

1. Basis for Allowable Emissions Code: **RULE 40.CFR 63.7500**	2. Future Effective Date of Allowable Emissions: **09/13/2007**
3. Allowable Emissions and Units: **0.07 lb/mmBTU**	4. Equivalent Allowable Emissions: **36.75** lb/hour **137.97** tons/year

5. Method of Compliance:
Settling Chamber Electrostatic Precipitator

6. Allowable Emissions Comment (Description of Operating Method):
0.07 lb/mmBtu x 450 mmBtu/hr x 8760/2000 = 137.97 TPY
0.07 lb/mmBtu x 525 mmBtu/hr = 36.75 lb/hr

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –

POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **PM10**	2. Total Percent Efficiency of Control: **99.9% +**
3.Potential Emissions: **36.75** lb/hour **137.97** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): **NA** to tons/year	
6. Emission Factor: **0.07 lb/mmBtu** Reference: **assume same as PM**	7. Emissions Method Code: **0**
8. Calculation of Emissions: **hrly: 525 mmBtu/hr x 0.07 lb/mmBtu = 36.75 lbs/hr** **ann: 450 mmBtu/hr x 0.07 lb/mmBtu x 1/2000 tons/lbs x 8760 hr/year = 137.97 TPY**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -

ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method): **There are no rule based PM10 emission limits applicable to this boiler. For purposes of calculating emission increases and decreases PM10 is considered equal to PM. The electrostatic precipitator will capture PM10 as well**	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –

POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **SO2**	2. Total Percent Efficiency of Control: **99**
3.Potential Emissions: **420** lb/hour **220.95** tons/year	4. Synthetically Limited? [X] Yes [ ] No
5. Range of Estimated Fugitive Emissions (as applicable): **NA** to tons/year	
6. Emission Factor: **0.8 lb/mmBtu** Reference: **40 CFR 60.43(1)**	7. Emissions Method Code: **0**

8. Calculation of Emissions:

hrly: 525 mmBtu/hr x 0.8 lb/mmBtu = 420.00 lbs/hr

ann: 450 mmBtu/hr x 0.1121 lb/mmBtu x 1/2000 tons/lbs x 8760 hr/year = 220.95 TPY

9. Pollutant Potential/Estimated Fugitive Emissions Comment:

An annual CAP on SO_2 emissions is requested on this source in this application to avoid PSD permitting.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -

ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions **1** of **3**

1. Basis for Allowable Emissions Code: **RULE 40 CFR 60.43**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.8 lb/mmBtu**	4. Equivalent Allowable Emissions: **420** lb/hour **1,576.8** tons/year
5. Method of Compliance: **Alkali scrubber**	
6. Allowable Emissions Comment (Description of Operating Method): **0.8 lb/mmBtu x 450 mmBtu/hr x 8760/2000 = 1,576.8 TPY** **0.8 lb/mmBtu x 525 mmBtu/hr = 420 lb/hr**	

Allowable Emissions Allowable Emissions **2** of **3**

1. Basis for Allowable Emissions Code: **ESCPSD**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.1121 lb/mmBtu**	4. Equivalent Allowable Emissions: **58.85** lb/hour **220.95** tons/year
5. Method of Compliance: **Alkali scrubber and CEMS for SO_2**	
6. Allowable Emissions Comment (Description of Operating Method): **0.1121 lb/mmBtu x 450 mmBtu/hr x 8760/2000 = 220.95 TPY** **0.1121 lb mmBtu x 525 mmBtu/hr = 58.85 lb/hr** **Equivalent hourly and annual emissions are based on an annual averaging time.**	

Allowable Emissions Allowable Emissions **3** of **3**

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –

POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control: **See Comment.**
3. Potential Emissions: **157.5** lb/hour **379.95** tons/year	4. Synthetically Limited? [X] Yes [ ] No
5. Range of Estimated Fugitive Emissions (as applicable): **NA** to tons/year	
6. Emission Factor: **0.3 lb/mmBtu** Reference: **Hourly 40 CFR 60.44**	7. Emissions Method Code: **0**

8. Calculation of Emissions:

hrly:
525 mmBtu/hr x 0.3 lb/mmBtu = 157.5 lbs/hr

annual:
450 mmBtu/hr x 0.1928 lb/mmBtu x 8760/2000 = 379.95 TPY

9. Pollutant Potential/Estimated Fugitive Emissions Comment:

NO_x control is based on methods and designs that prevent the pollutant from forming, or minimizing the fuel bound NO_x that does form. Therefore it is not possible to calculate a control efficiency as if there were collection of a pollutant.

An annual CAP on NO_x emissions is requested on this emission unit in this application to avoid PSD permitting.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -

ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions **1** of **2**

1. Basis for Allowable Emissions Code: **RULE 40 CFR 60.44**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.3 lb/mmBtu**	4. Equivalent Allowable Emissions: **157.5** lb/hour **591.3** tons/year

5. Method of Compliance:
boiler design, staged combustion and flue gas recirculation

6. Allowable Emissions Comment (Description of Operating Method):
0.3 lb/mmBtu x 450 mmBtu/hr x 8760/2000 = 591.3 TPY
0.3 lb/mmBtu x 525 mmBtu/hr = 157.5 lb/hr

Allowable Emissions Allowable Emissions **2** of **2**

1. Basis for Allowable Emissions Code: **ESCPSD**	2. Future Effective Date of Allowable Emissions: **11/2005**
3. Allowable Emissions and Units: **379.95 tons per year**	4. Equivalent Allowable Emissions: **101.20** lb/hour **379.95** tons/year

5. Method of Compliance:
CEMS for NO_x. The boiler will minimize NO_x formation by furnace design, flue gas recirculation and staged combustion. If these methods are inadequate the boiler is designed to have SNCR installed.

6. Allowable Emissions Comment (Description of Operating Method):
0.1928 lb/mmBtu x 450 mmBtu/hr x 8760/2000 = 379.95 TPY
0.1928 lb/mmBTU x 525 mmBtu/hr = 101.20 lb/hr
Equivalent hourly and annual emissions are based on an annual averaging time.

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year

5. Method of Compliance:

6. Allowable Emissions Comment (Description of Operating Method):

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –

POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control: **See Comment.**
3. Potential Emissions: **105** lb/hour **394.2** tons/year	4. Synthetically Limited? ☐ Yes [X] No
5. Range of Estimated Fugitive Emissions (as applicable): **NA** to tons/year	
6. Emission Factor: **0.2 lb/mmBtu** Reference:	7. Emissions Method Code:
8. Calculation of Emissions: **hrly: 525 mmBtu/hr x 0.2 lb/mmBtu = 105 lbs/hr** **annual: 450 mmBtu/hr x 0.2 lb/mmBtu X 8760/2000 = 394.2 TPY**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **CO control is based on methods and designs that prevent the pollutant from forming. Therefore it is not possible to calculate a control efficiency as if there were collection of a pollutant.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -

ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

<u>**Allowable Emissions**</u> Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method): **There is no rule based emission limit for CO for this boiler. CO emissions for this boiler are expected to be significantly less than experienced with the less efficient existing boilers that CO emissions decrease and PSD limits should not be of concern.**	

<u>**Allowable Emissions**</u> Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

<u>**Allowable Emissions**</u> Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –

POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

<u>Potential/Estimated Fugitive Emissions</u>

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **Pb**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.38** lb/hour **1.65** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): **NA** to tons/year	
6. Emission Factor: **see calculation and commment** Reference: **calculated from NCASI**	7. Emissions Method Code:

8. Calculation of Emissions:

451,425t bark/yr X 0.0073 lb Pb/ton bark = 3,295.4 lbs/yr
46,269 t knots/yr x 0.0013 lb Pb/ton knots = 60.2 lb/yr

3355.6 lb/yr /8760 = 0.38 lb/hr

9. Pollutant Potential/Estimated Fugitive Emissions Comment:

Pb emissions from burning bark and knots are based on the Pb in bark and wood, and assuming all Pb is emitted, where generally it stays with the bottom ash. Further this calculation does not consider the collection efficiency of the ESP. Thus this is a worst case projection.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -

ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method): **There are no regulation based emission limits for Pb applicable to this boiler.**	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

G. VISIBLE EMISSIONS INFORMATION

Complete if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation **1** of **3**

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: [X] Rule [ ] Other
3. Allowable Opacity: Normal Conditions: **30** % Exceptional Conditions: **40** % Maximum Period of Excess Opacity Allowed: **2** min/hour	
4. Method of Compliance: **Electrostatic Precipitator**	
5. Visible Emissions Comment: **62-296.410(2)(b)(1)**	

Visible Emissions Limitation: Visible Emissions Limitation **2**_ of **3**

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: [X] Rule [ ] Other
3. Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: **27** % Maximum Period of Excess Opacity Allowed: **6** min/hour	
4. Method of Compliance: **Electrostatic Precipitator**	
5. Visible Emissions Comment: **40 CFR 60.42**	

Visible Emissions Limitation: Visible Emissions Limitation **3**_ of **3**

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: [X] Rule [ ] Other
3. Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: **27** % Maximum Period of Excess Opacity Allowed: **6** min/hour	
4. Method of Compliance: **Electrostatic Precipitator**	
5. Visible Emissions Comment:**40 CFR 63. 7500**	

H. CONTINUOUS MONITOR INFORMATION

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor **1** of **4**

1. Parameter Code: **VE**	2. Pollutant(s): **visible emissions (opacity)**
3. CMS Requirement: [X] Rule [ ] Other	
4. Monitor Information... **See comment** Manufacturer: Model Number:	Serial Number:
5. Installation Date: **projected by 11/2006**	6. Performance Specification Test Date: **projected by 5/2007**
7. Continuous Monitor Comment: **Rule – 40 CFR 63.7525 and 63.7535 This monitor has not been selected at submittal of this construction application. The details of the selected monitor will be submitted with the Title V operating permit to follow. The location of this instrument is also to be determined as there is a wet scrubber prior to stack exit.**	

Continuous Monitoring System: Continuous Monitor **2** of **4**

1. Parameter Code: **EM**	2. Pollutant(s): **SO2**
3. CMS Requirement: [x] Rule [ ] Other	
4. Monitor Information...**See comment** Manufacturer: Model Number:	Serial Number:
5. Installation Date: **projected by 11/2006**	6. Performance Specification Test Date: **projected by 5/2007**
7. Continuous Monitor Comment: **There is a rule requirement for a SO2 CEM (40 CFR 60.45(a)). Also, a SO2 CAP is requested for this boiler to avoid PSD review. This monitor is proposed to document compliance with the emissions CAP.** **This monitor has not been selected at submittal of this construction application. The details of the selected monitor will be submitted with the Title V operating permit to follow.**	

H. CONTINUOUS MONITOR INFORMATION (CONTINUED)

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor **3** of **4**

1. Parameter Code: **EM**	2. Pollutant(s): **NOX**
3. CMS Requirement: ☐ Rule	☒ Other
4. Monitor Information...**See comment** Manufacturer: Model Number:	Serial Number:
5. Installation Date: **projected 11/2006**	6. Performance Specification Test Date: **projected 5/2007**

7. Continuous Monitor Comment:

There is no rule requirement for a NO_x CEM (40 CFR 60.45(b)(3)). However, a NO_x CAP is requested for this boiler to avoid PSD review. This monitor is proposed to document compliance with the emissions CAP.

This monitor has not been selected at submittal of this construction application. The details of the selected monitor will be submitted with the Title V operating permit to follow.

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

1. Parameter Code: **FLOW**	2. Pollutant(s): **volumetric flow rate**
3. CMS Requirement: ☐ Rule	☒ Other
4. Monitor Information... **See comment** Manufacturer: Model Number:	Serial Number:
5. Installation Date: **projected 11/2006**	6. Performance Specification Test Date: **projected 5/2007**

7. Continuous Monitor Comment:

There is no rule requirement for a flow monitor. However, annual CAPs for NO_x and SO2 are requested for this boiler to avoid PSD review. This monitor is proposed to document compliance with the emissions CAP.

This monitor has not been selected at submittal of this construction application. The details of the selected monitor will be submitted with the Title V operating permit to follow.

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   [X] Attached, Document ID: 6 previously Submitted, Date ___

2. Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   [X] Attached, Document ID: 7 [ ] Previously Submitted, Date ______

3. Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   [X] Attached, Document ID: 8 [ ] Previously Submitted, Date ______

4. Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   [ ] Attached, Document ID: ______ [ ] Previously Submitted, Date ______
   [X] Not Applicable (construction application)

5. Operation and Maintenance Plan (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   [X] Attached, Document ID: 9 [ ] Previously Submitted, Date ______
   [ ] Not Applicable

6. Compliance Demonstration Reports/Records
   [ ] Attached, Document ID: ______
   Test Date(s)/Pollutant(s) Tested: ______
   [ ] Previously Submitted, Date: ______
   Test Date(s)/Pollutant(s) Tested: ______
   [ ] To be Submitted, Date (if known): ______
   Test Date(s)/Pollutant(s) Tested: ______
   [X] Not Applicable

   Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.

7. Other Information Required by Rule or Statute
   [ ] Attached, Document ID: ______ [X] Not Applicable

Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(6) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)) ☐ Attached, Document ID: ____________ ☒ Not Applicable	
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(5)(h)6., F.A.C., and Rule 62-212.500(4)(f), F.A.C.) ☐ Attached, Document ID: ____________ ☒ Not Applicable	
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only) ☒ Attached, Document ID: **10**______ ☐ Not Applicable	

Additional Requirements for Title V Air Operation Permit Applications

1. Identification of Applicable Requirements ☐ Attached, Document ID: _	
2. Compliance Assurance Monitoring ☐ Attached, Document ID: _ ☒ Not Applicable	
3. Alternative Methods of Operation ☐ Attached, Document ID: _ ☒ Not Applicable	
4. Alternative Modes of Operation (Emissions Trading) ☐ Attached, Document ID: _ ☒ Not Applicable	
5. Acid Rain Part Application ☐ Certificate of Representation (EPA Form No. 7610-1) ☐ Copy Attached, Document ID: ☐ Acid Rain Part (Form No. 62-210.900(1)(a)) ☐ Attached, Document ID:____________ ☐ Previously Submitted, Date:_________ ☐ Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) ☐ Attached, Document ID:____________ ☐ Previously Submitted, Date:_________ ☐ New Unit Exemption (Form No. 62-210.900(1)(a)2.) ☐ Attached, Document ID:____________ ☐ Previously Submitted, Date:_________ ☐ Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) ☐ Attached, Document ID:____________ ☐ Previously Submitted, Date:_________ ☐ Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) ☐ Attached, Document ID:____________ ☐ Previously Submitted, Date:_________ ☐ Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) ☐ Attached, Document ID:____________ ☐ Previously Submitted, Date:_________ ☒ Not Applicable	

Additional Requirements Comment

No BACT analysis is required because this is not a PSD permit. Nevertheless, the boiler is using state of the art design in this conversion plus modern ESP and scrubbing techniques.

A GEP analysis is not required because this is not a PSD permit appplication. However, the stack does not exceed 2.5 times the height of the nearest building. It is higher than the existing stacks it is replacing. The applicant submitted modeling in 1991 to demonstrate these stacks were high enough to avoid downwash effects.

III. EMISSIONS UNIT INFORMATION - PG

Title V Air Operation Permit Application - For Title V air operation permitting only, emissions units are classified as regulated, unregulated, or insignificant. If this is an application for Title V air operation permit, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each regulated and unregulated emissions unit addressed in this application for air permit. Some of the subsections comprising the Emissions Unit Information Section of the form are optional for unregulated emissions units. Each such subsection is appropriately marked. Insignificant emissions units are required to be listed at Section II, Subsection C.

Air Construction Permit or FESOP Application - For air construction permitting or federally enforceable state air operation permitting, emissions units are classified as either subject to air permitting or exempt from air permitting. The concept of an "unregulated emissions unit" does not apply. If this is an application for air construction permit or FESOP, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air permitting are required to be listed at Section II, Subsection C.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit Application – Where this application is used to apply for both an air construction permit and a revised/renewal Title V air operation permit, each emissions unit is classified as either subject to air permitting or exempt from air permitting for air construction permitting purposes and as regulated, unregulated, or insignificant for Title V air operation permitting purposes. **The air construction permitting classification must be used to complete the Emissions Unit Information Section of this application for air permit.** A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air construction permitting and insignificant emissions units are required to be listed at Section II, Subsection C.

If submitting the application form in hard copy, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application must be indicated in the space provided at the top of each page.

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

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

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

Emissions Unit Description and Status

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

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

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

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

2. Description of Emissions Unit Addressed in this Section: **This emission unit is the pulping segment of the facility which is involved with the cooking wood chips and the manufacture of the cooking acid. The construction permit covers the addition of a new digester, No. 6 digester, to five existing digesters.**

3. Emissions Unit Identification Number: 005

4. Emissions Unit Status Code: **A**	5. Commence Construction Date: **11/2005**	6. Initial Startup Date: **11/2006**	7. Emissions Unit Major Group SIC Code: **26**	8. Acid Rain Unit? [ ] Yes [X] No

9. Package Unit: **NA**
Manufacturer: Model Number:

10. Generator Nameplate Rating: **NA** MW

1. Emissions Unit Comment:
No. 6 digester was added in 1998 based on analyses and permitting at that time. That analysis was based on production and limited production to 153,210 ADMT to avoid PSD permitting. This application re-examines that analysis and seeks to change the production limit in the permit issued.

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description:

The pulping segment of the mill is required to control 2 pollutants, sulfur dioxide (SO_2) and methanol, a component of VOC. Sulfur dioxide is collected from digesters blow tanks, washers and cooking acid tanks and used to make or strengthen cooking liquor. Streams containing SO_2 that are too weak to economically or practically recover are passed through an alkaline packed scrubber prior to discharge.

Methanol is collected at the pulping and washing and evaporation segments of the mill and biologically destroyed in the waste water treatment plant. Methanol collection is by condensation and solution in water which is conveyed via the sewer system to the waste water treatment system. Methanol is a VOC and the condenser/scrubbers used for its collection also collect VOCs. The methanol collection system was not installed until 2001. Calculations are based on 2002 and 2003 calendar years as these were the first two years of operation under Subpart S MACT. Using older emissions would result in an inflated baseline by not accounting for more stringent emission reductions imposed by Subpart S MACT.

2. Control Device or Method Code(s): **050, 050**

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1.	Maximum Process or Throughput Rate: **175,000 ADMT**
2.	Maximum Production Rate: **175,000 ADMT**
3.	Maximum Heat Input Rate: million Btu/hr **NA**
4.	Maximum Incineration Rate: pounds/hr **NA** tons/day
5.	Requested Maximum Operating Schedule: **8** hours/day **7** days/week **52** weeks/year **8760** hours/year
6.	Operating Capacity/Schedule Comment:

C. EMISSION POINT (STACK/VENT) INFORMATION
(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: **PG**	2. Emission Point Type Code: **3**	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: **See Attachment 11 for Flow Sheet and Emission Unit Designations of equipment and emission points.**		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: **See Attachment 11**		
5. Discharge Type Code: **V**	6. Stack Height: feet **110**	7. Exit Diameter: feet **3**
8. Exit Temperature: **122** °F	9. Actual Volumetric Flow Rate: **28,350** acfm	10. Water Vapor: **13%**
11. Maximum Dry Standard Flow Rate: **25,400** dscfm	12. Nonstack Emission Point Height: **NA** feet	
13. Emission Point UTM Coordinates... Zone: East (km): North (km):	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)	
15. Emission Point Comment:		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment **1** of **1**

1. Segment Description (Process/Fuel Type): **This segment is the pulp production of the facility including #6 digester.**		
2. Source Classification Code (SCC): **3070010**	3. SCC Units: **lb/Air Dried Short Ton Unbleached Pulp**	
4. Maximum Hourly Rate: **41.6**	5. Maximum Annual Rate: **267,922**	6.Estimated Annual Activity Factor: **NA**
7. Maximum % Sulfur: **NA**	8. Maximum % Ash: **NA**	9. Million Btu per SCC Unit: **NA**
10. Segment Comment: **175,000 ADMT/yr x 1.1023 ST/MT x 1.3889 UB/B = 267,922 ADSTUP (air dry short ton unbleached pulp)**		

Segment Description and Rate: Segment __ of __

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

D. SEGMENT (PROCESS/FUEL) INFORMATION (CONTINUED)

Segment Description and Rate: Segment _ of _

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

Segment Description and Rate: Segment _ of _

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

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
SO2	050		EL
VOC	050		EL

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –

POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **SO2**	2. Total Percent Efficiency of Control: **estimated 95%**
3.Potential Emissions: **61.0** lb/hour **267.00** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): **NA** to tons/year	
6. Emission Factor: **250 ppm** Reference: **CEM**	7. Emissions Method Code: **1**
8. Calculation of Emissions: **hourly** **250 ppm/10^6 x 25,400 dscfm x 60 x 0.0025 mole SO_2/dscf x 64 lb/mole = 61.0 lbs/hr** **annual** **61.0 lb/hr x 8760/2000 = 267.00 TPY**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

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

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **250 ppm volume**	4. Equivalent Allowable Emissions: **61.0** lb/hour **267.00** tons/year
5. Method of Compliance: **Alkaline Scrubber and Continuous Stack Monitor**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –

POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **Methanol**	2. Total Percent Efficiency of Control: **estimated 95%**
3. Potential Emissions: **60.56** lb/hour **265.24** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): **NA** to tons/year	
6. Emission Factor: Reference: **40 CFR 63.444**	7. Emissions Method Code: **1**

8. Calculation of Emissions:

annual
2.2 lb/ODSTUP X 267,922 ADSTUP x 0.9 OD/AD x 1 T/ 2000 LB = 265.24 TPY

hourly
265.24 T/yr x 2000 lb/T x 1 yr/365 op days x 1 day / 24 hr = 60.56 lb/hr

9. Pollutant Potential/Estimated Fugitive Emissions Comment:
40 CFR 63.444 limits this emission unit plus the evaporator emissions plus emissions from the wastewater treatment system to 2.2 lb methanol per oven dry unbleached short ton. The actual emissions from this source could vary as long as the total is not exceeded. This provision is all ready part of theTitle V permit and no change to it is being requested.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -

ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

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

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **2.2 lb/oven dry unbleached short ton**	4. Equivalent Allowable Emissions: lb/hour **265.24** tons/year
5. Method of Compliance: **Continuous Monitoring System**	
6. Allowable Emissions Comment (Description of Operating Method): **175,000 ADMT x 0.992 OD/ADMT / 0.72 UB/B x 2.2 lb/ton / 2000 = 265.24 TPY**	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

G. VISIBLE EMISSIONS INFORMATION

Complete if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation 1_ of 1

1. Visible Emissions Subtype: VE	2. Basis for Allowable Opacity: [X] Rule [ ] Other
3. Allowable Opacity: Normal Conditions: 30 % Exceptional Conditions: 40% Maximum Period of Excess Opacity Allowed: 2 min/hour	
4. Method of Compliance: Method 9	
Visible Emissions Comment: FAC 62-296.320(4)(b)(1) This is wet stack on a process that does not produce particulate emissions.	

Visible Emissions Limitation: Visible Emissions Limitation ___ of __

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: [ ] Rule [ ] Other
3. 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[2] of [2]

H. CONTINUOUS MONITOR INFORMATION

Complete if this emissions unit is or would be subject to continuous monitoring.

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

1. Parameter Code: **EM**	2. Pollutant(s): **SO2**
3. CMS Requirement:	☐ Rule ☒ Other
4. Monitor Information... Manufacturer: **Siemans** Model Number: **Ultramat SE:SSN-EN-40**	Serial Number:
5. Installation Date: **March 23, 1995**	6. Performance Specification Test Date: **June 16, 1995**
7. Continuous Monitor Comment: **Continuous emission monitor required by condition 6 of air operating permit AO45-182645.**	

Continuous Monitoring System: Continuous Monitor ___ of ___

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

H. CONTINUOUS MONITOR INFORMATION (CONTINUED)

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor ___ of ___

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

Continuous Monitoring System: Continuous Monitor ___ of ___

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) [X] Attached, Document ID: 11 ☐ Previously Submitted, Date ____
2. Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: _ ☐ Previously Submitted, Date ____
3. Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) [X] Attached, Document ID: 12 ☐ Previously Submitted, Date ____
4. Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: _ ☐ Previously Submitted, Date ____ [X] Not Applicable (construction application)
5. Operation and Maintenance Plan (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) [X] Attached, Document ID: 13 ☐ Previously Submitted, Date ____ ☐ Not Applicable

6. Compliance Demonstration Reports/Records ☐ Attached, Document ID: ________ Test Date(s)/Pollutant(s) Tested: ________________ ________________ ☐ Previously Submitted, Date: ______ Test Date(s)/Pollutant(s) Tested: ________________ ________________ ☐ To be Submitted, Date (if known): ________ Test Date(s)/Pollutant(s) Tested: ________________ ________________ ☒ Not Applicable Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.
7. Other Information Required by Rule or Statute ☐ Attached, Document ID: ________ ☒ Not Applicable

EMISSIONS UNIT INFORMATION
Section[2] of [2]

Additional Requirements for Air Construction Permit Applications

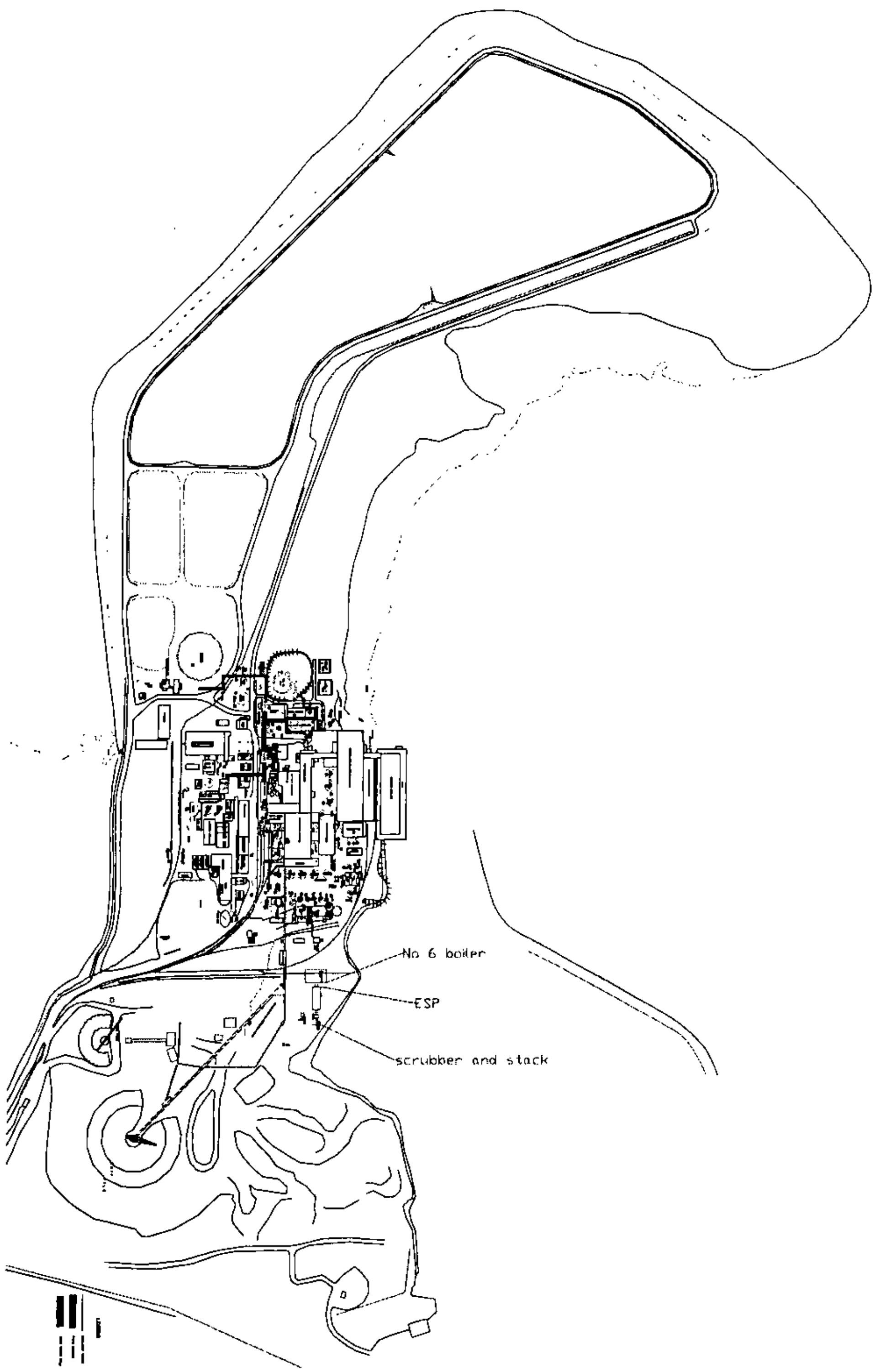
1. Control Technology Review and Analysis (Rules 62-212.400(6) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)) ☐ Attached, Document ID: ____ ☒ Not Applicable	
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(5)(h)6., F.A.C., and Rule 62-212.500(4)(f), F.A.C.) ☐ Attached, Document ID: ____ ☒ Not Applicable	
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only) ☐ Attached, Document ID: ____ ☒ Not Applicable	

Additional Requirements for Title V Air Operation Permit Applications

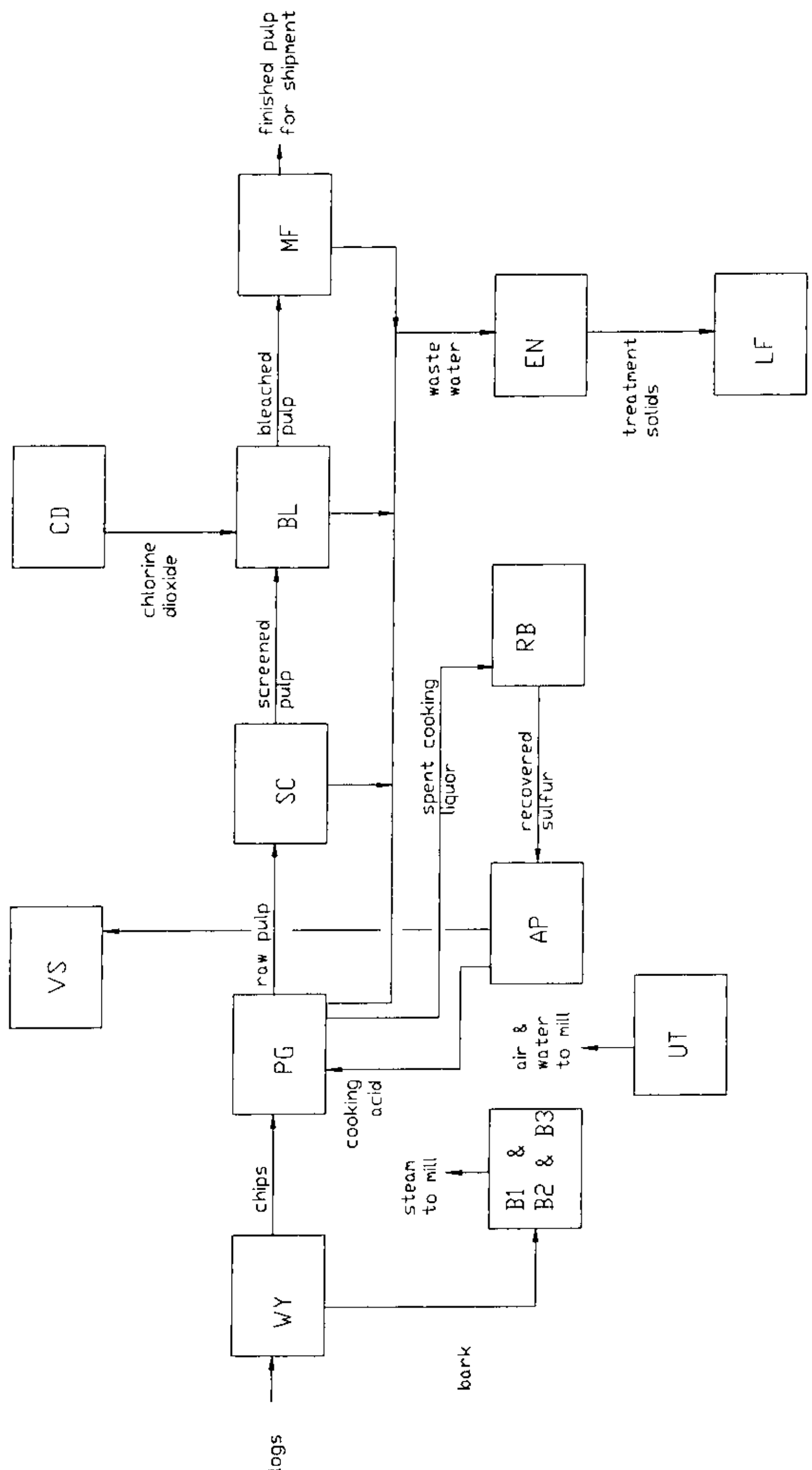
1. Identification of Applicable Requirements ☐ Attached, Document ID: _	
2. Compliance Assurance Monitoring ☐ Attached, Document ID: _ ☒ Not Applicable	
3. Alternative Methods of Operation ☐ Attached, Document ID: _ ☒ Not Applicable	
4. Alternative Modes of Operation (Emissions Trading) ☐ Attached, Document ID: _ ☒ Not Applicable	
5. Acid Rain Part Application ☐ Certificate of Representation (EPA Form No. 7610-1) ☐ Copy Attached, Document ID: ☐ Acid Rain Part (Form No. 62-210.900(1)(a)) ☐ Attached, Document ID:____ ☐ Previously Submitted, Date:____ ☐ Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) ☐ Attached, Document ID:____ ☐ Previously Submitted, Date:____ ☐ New Unit Exemption (Form No. 62-210.900(1)(a)2.) ☐ Attached, Document ID:____ ☐ Previously Submitted, Date:____ ☐ Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) ☐ Attached, Document ID:____ ☐ Previously Submitted, Date:____ ☐ Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) ☐ Attached, Document ID:____ ☐ Previously Submitted, Date:____ ☐ Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) ☐ Attached, Document ID:____ ☐ Previously Submitted, Date:____ ☒ Not Applicable	

Additional Requirements Comment

ATTACHMENT 1 - Facility Plot Plan



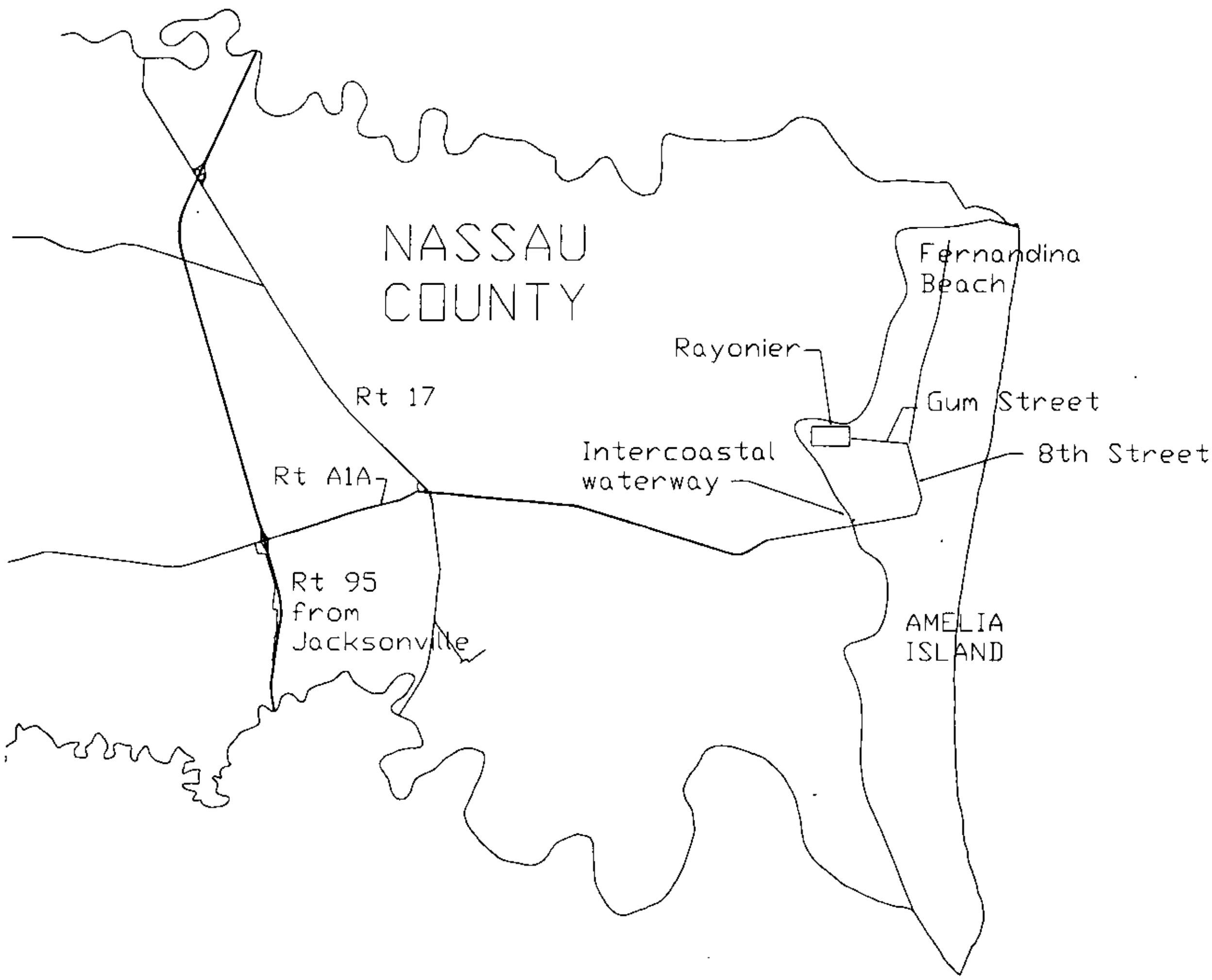
ATTACHMENT 2 - Facility Flow Diagram



ATTACHMENT 3 - List of Pollutants Emitted by Facility

PM10	(Particles)	A	N
SO2	(Sulfur Dioixde)	A	N
NOx	(Nitrogen Dioxide)	A	Y
CO	(Carbon Monoxide)	A	N
VOC	(Volatile Organic Compounds)	A	N
HAPS	(Total Hazardous Air Pollutant)	A	N
H115	(Methanol)	A	N
H038	(Chlorine)	A	N
H043	(Chloroform)	A	N
PB	(Lead)	B	N
H047	(Cobalt)	B	N
H120	(MEK)	A	N
H001	(Acetaldehyde)	A	N
H106	(HCl)	B	N
H095	(Formaldehyde)	B	N
H006	(Acrolein)	B	N
H118	(Chloromethane)	B	N
H163	(Styrene)	B	N
CFC	(totalCFCs)	B	N
H128	(Methylene chloride)	B	N
H033	(Carbon Tetrachloride)	B	N
H017	(Benzene)	B	N
H123	(Methyl Isobutyl Ketone)	B	N
H169	(Toluene)	B	N
H041	(Chlorobenzene)	B	N
H085	(Ethyl benzene)	B	N
H187	(Xylene)	B	N
H166	(1,1,2,2-tetrachloroethane)	B	N
H061	(1,4, dichlorobenzene)	B	N
H174	(1,2,4-trichlorobenzene)	B	N
H165	(TCDD)	B	N
H2S	(Hydrogen sulfide)	B	N
H167	(Tetrachloroethene)	B	N
H176	(Trichloroethylene)	B	N
H119	(1,1,1-trichloroethane)	B	N
H104	(Hexane)	B	N
H0323	(Carbon disulfide)	B	N
H117	(Bromomethane)	B	N
	(Chlorine dioxide)	A	N
H113	(Manganese)	B	N
H114	(Mercury)	B	N
H133	(Nickel)	B	N
H148	(Phosphorous)	B	N

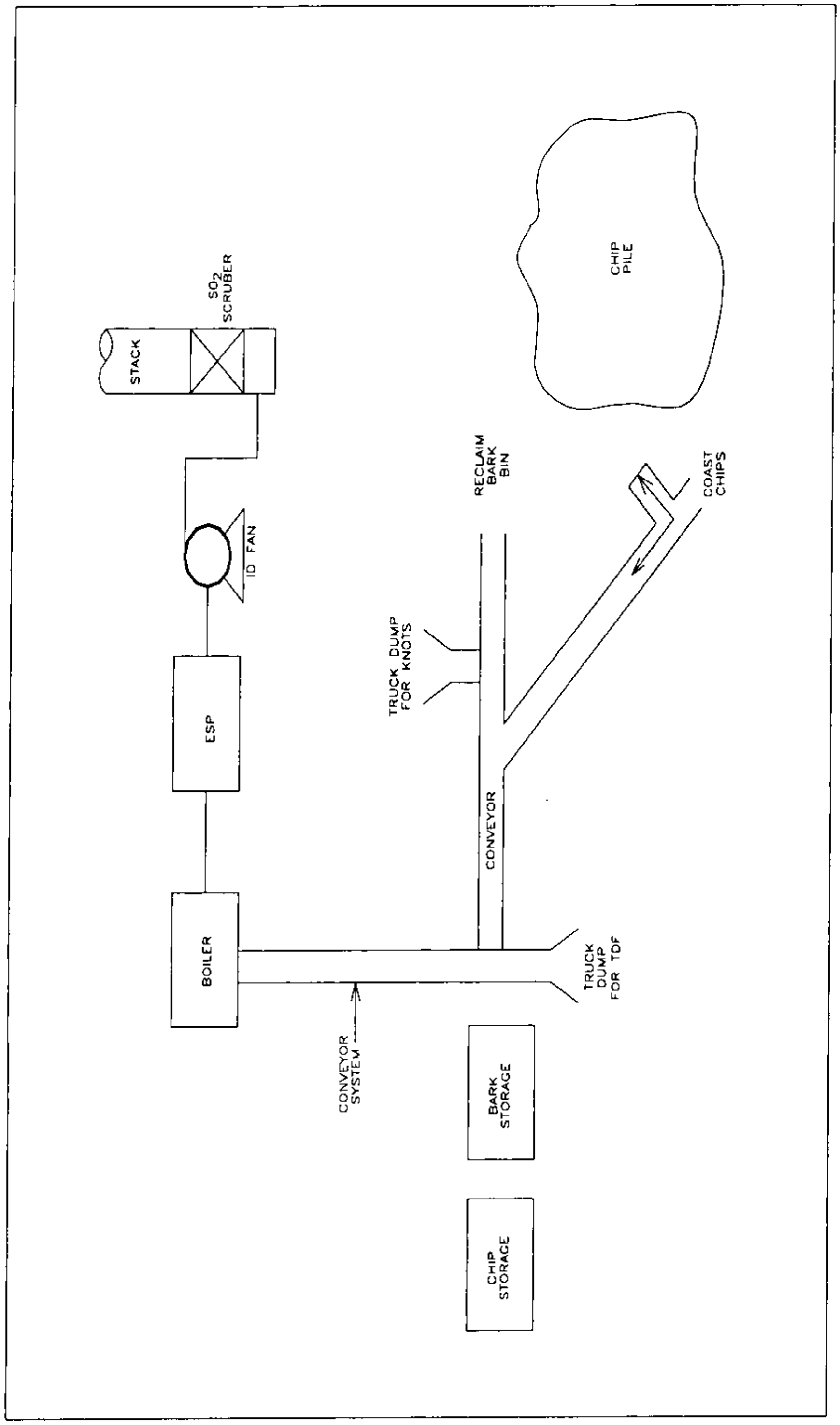
ATTACHMENT 4 - Area Map



ATTACHMENT 5 - Description Of Construction and Rule Applicability Analysis

See Separate Document

ATTACHMENT 6 - PB06 Process Flow Diagram



ATTACHMENT 7 - PB06 Fuel Analysis

Four main fuels will be fired in power boiler No. 6: bark, oil, knots, landscape waste and Tire Derived Fuel. The proximate and ultimate analyses for each is given below.

Fuel	Bark	Knots	TDF	#6 Fuel Oil
Proximate Analysis				
Fixed Carbon	9.95	4.94	27.5	
Volatiles	40.19	27.71	65.5	
Sulfur	0.03	0.40	1.85	
Ash	2.27	0.41	4.78	
Moisture	47.59	66.94	0.37	
Ultimate Analysis				
Carbon	28.07	19.49	83.00	85.70
Hydrogen	3.00	2.10	7.50	10.50
Oxygen	18.82	10.49	0.50	0.92
Nitrogen	0.22	0.17	0.37	0.92
Chlorine	0.01	0.01		
Sulfur	0.03	0.4	1.85	2.50
Ash	2.27	0.41	4.78	0.08
Moisture	47.59	66.94	2.00	

ATTACHMENT 8 - PB06 Detailed Description of Control Equipment

PARTICULATE EMISSION CONTROL EQUIPMENT

Ash Hopper. There will be a settling chamber ahead of the electrostatic precipitator. This piece of equipment is referred to as the ash hopper. It will allow large particles to settle and reduce the ash and grain loading to the ESP. This hopper will have a screw conveyor bottom to remove this ash for disposal.

Electrostatic Precipitator. This unit will be a rigid electrode and collector plate design having four fields with a dedicated transformer/rectifier (T/R) set for each field. To minimize reintrainment each field will have its own ash-hopper with a screw conveyor discharge.

An opacity monitor is not required by rule, but one will be installed following the electrostatic precipitator and before the scrubber. This will be used to control boiler operation in addition to other control instruments and equipment. This monitor will not be monitoring the emissions as they exit the stack because there is a wet scrubber prior to stack top exhaust. The opacity monitor can not operate in a saturated gas stream.

SULFUR DIOXIDE EMISSION CONTROL EQUIPMENT

Alkaline Wet Scrubber. After the Induced Draft Fan will be an SO_2 gas scrubber. A spray of 4,000 gpm of recirculated alkaline water will cascade from showers over chevrons and louvre type packings. This type scrubber has a low pressure drop of about 2 inches WG. It is expected to remove 90% or more of the SO_2 in the inlet. The alkalinity of the wood ash is expected to also achieve some SO2 capture.

NITROGEN OXIDES EMISSION CONTROL EQUIPMENT

Initially no collection equipment will be installed, however, provision will be made to install this control equipment. The boiler furnace will be lengthened to increase residence time allowing a lower flame temperature through staged combustion which decreases NO_x formation. Also flame temperature and the rate of oxidation will be controlled through flue gas recirculation. Should it be necessary the boiler will also be capable of receiving a SNCR. Installation.

ATTACHMENT 9 - PB06 Operation and Maintenance Plan

Number 6 Power Boiler
Rayonier Performance Fibers, LLC.
Fernandina Mill

Brief Description of the Boiler

No. 6 power boiler is a reconstruction of the Smurfit Jacksonville Mill No. 10 Combustion Engineering [CE VU-40] power boiler originally built in 1982, modified to burn high moisture fuels. No. 6 power boiler has a nominal steam production capacity of 265,000 lb/hr at 900 psig and 875°F. Routinely the boiler burns bark and wood waste. It is capable of supplementing with No. 6 fuel oil to a maximum capability of 310,000 lb/hr steam production when the recovery boiler is out of service. The combustion is accomplished in a Bubbling Fluidized Bed [BFB]. It has the capability of burning bark, wood waste, reject knots, tire derived fuel [TDF] and the mill's on-specification used oil.

In addition to the very efficient BFB combustion, No. 6 power boiler is equipped with a new electrostactic precipitator, a relocated scrubber and the nozzles for a selective non-catalytic reduction [SNCR] system. The SNCR system will not be installed nor operated unless the nitrogen oxide emissions are higher than expected. A new continuous emissions monitoring system [CEMS] is installed to measure opacity, carbon monoxide, sulfur dioxide, nitrogen dioxides and oxygen.

Maintenance and Inspection

All systems and equipment are set up for routine preventative maintenance inspections and or calibrations.
Operators inspect all critical equipment for any type of defect on a daily basis.
Deficiencies that cannot be corrected by the operator are to be appropriately recorded and reported so that necessary repairs may be made in a timely manner.
A complete inspection of all aspects of the boiler will be made during each maintenance repair shutdown.

The results of the inspections will:
Identify and analyze potentially unsafe conditions during simulated inspections
Recommend corrective action
Detect hidden hazardous conditions during inspections
Communicate findings effectively, both verbally and in writing
The inspections involve ensuring the safe operation of the boiler by performing periodic inspections and by close monitoring of all repair work. The boiler to be installed will be built to a standardized nationwide construction code, the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code.
The inspections will be performed by an inspector commissioned by the National Board of Boiler and Pressure Vessel Inspectors

Monitoring of Operations and Records
Records of the duration and occurrence of startups, shutdowns, and malfunctions of the boiler and associated air emission control systems and any period during which the continuous monitoring system is inoperative shall be recorded and the record maintained for a period of five years. A record of boiler downtime due to any maintenance activity shall be maintained.

The continuous emissions monitoring system shall be continuously monitored. When an excursion of a parameter is indicated, corrective action will be immediately initiated.

The daily feed rate of bark & wood waste, No. 6 fuel oil, knots and any other fuel shall be measured and recorded.

Sulfur Dioxide Emissions Control Systems

Brief Description of the System

The oxides of sulfur found in the flue gases are removed with a wet scrubber. The wet scrubber is a venturi type device. Flue gas is accelerated through a nozzle and deluged with a scrubbing liquid. The scrubbing liquid is a solution of caustic soda.

Spray nozzles are arranged in the tower to spray the scrubbing liquor into the flue gas. The spray nozzles are full cone non-clogging nozzles.
When the scrubbing liquor comes in contact with sulfur dioxide in the flue gas, the sulfur dioxide is converted and then removed from the aqueous stream.
The scrubber features a high amount of active surface area with random dumped packing. The packing material breaks the liquid streams into multiple, even surface films that create intimate gas/liquid contact at a low-pressure drop. The Scrubber is expected to remove greater than 90% of the Sulfur Dioxide entering the vessel.

Maintenance and Inspection

All systems and equipment are set up for routine preventative maintenance inspections and or calibrations.
Operators inspect all critical equipment for any type of defect on a daily basis.
Deficiencies that cannot be corrected by the operator are to be appropriately recorded and reported so that necessary repairs may be made in a timely manner.
A complete inspection of all aspects of the scrubber will be made during each maintenance repair shutdown.
Scrubber spray chambers and nozzles will be inspected regularly to ensure they are not plugged.
The packing section will be inspected often to ensure against solids buildup that would plug portions of the pack.
The scrubber mist eliminator will also be inspected on a regular basis. The catchment on a chevron baffle can become filled with solids, rendering it ineffective.
The scrubber recirculation system will be kept reasonably clean to ensure the solution is capable of gas absorption; to minimize buildup of solids in packed and mist eliminator sections; and to prevent plugging of spray chambers and nozzles.
A continuous addition of water, up to five pct of the total recirculation rate will be added to the recirculation tank and simultaneously overflowed to waste treatment.
The recirculation tank will also be kept clean of sediment. These solids are easily stirred up and will inevitably contribute to plugging of spray nozzles, packing sections and the mist eliminator section.

Monitoring of Operations and Records

A log will be maintained of all observations, deviations and corrective actions taken for a period of five years.

The wet scrubber will be equipped with devices to continuously measure the scrubber water flow rate and the differential pressure drop across the scrubber demister pads. The wet scrubber monitoring devices used to continuously measure the scrubber water flow rate and the differential pressure drop across the scrubber demister pads shall be observed with a frequency of not less than once per day.

Each monitoring device will be installed, maintained, calibrated and operated in accordance with approved procedures which shall include, as a minimum, the manufacturer's written requirements or recommendations. If the manufacturer's written requirements or recommendations are not available, Rayonier will establish the written procedures.

Each monitoring device shall be provided with adequate access for inspection and shall be in operation when the control device is operating.

Nitrogen Dioxide Emissions Control Systems

Selective Non-Catalytic Reduction

Brief Description of the System

The design of the bubbling fluidized bed combustor minimizes nitrogen oxide formation. However, nozzle ports for an SNCR [selective non-catalytic reduction] system are provided on the boiler in case the NOX emissions are higher than expected. The remainder of the SNCR system will be installed only if there are unforeseen problems with NOX emissions.

Maintenance and Inspection

None planned.

Monitoring of Operations and Records

A CEM for nitrogen compounds is installed on the boiler's final emissions. Records of the duration and occurrence of startups, shutdowns, and malfunctions of the boiler and associated air emission control systems and any period during which the continuous monitoring system is inoperative shall be recorded and the record maintained for a period of five years. A record of SNCR downtime due to any maintenance activity shall be maintained if installed.

The continuous emission monitoring system (CEMS) will be installed for the determination of a gas or particulate matter concentration or emission rate using pollutant analyzer measurements and a conversion equation, graph, and computer program to produce results in units of the applicable emission limitation or standard. The system will measure emissions of NOx, SO2, CO2, oxygen and opacity.

The CEM system will comply with all Federal and State requirements that may apply. Specifically, the system complies with 40CFR60. The CEM system will meet all monitoring and reporting requirements outlined in the Title V Permit.

Performance Specifications will be used for evaluating the acceptability of the CEMS at the time of or soon after installation and whenever specified in the regulations. All performance tests must be completed within 30 days after the emission source has begun operation. These reports should contain all pertinent data regarding performance testing.

Quality assurance procedures will be used to evaluate the effectiveness of quality control (QC) and quality assurance (QA) procedures and the quality of data produced by the CEM that will be used for determining compliance with the emission standards on a continuous basis as specified in the applicable regulation.

Particulate Control Devices

Electrostatic Precipitator

Brief Description of the System

The dust laden gases are drawn into one side of the Electrostatic Precipitator Chamber where high voltage electrodes impart a negative charge to the particles entrained in the gas. These negatively charged particles are then attracted to a grounded collecting surface, which is positively charged. The gas then leaves the box up to 99 % cleaner than when it entered.
Inside the Electrostatic Precipitator Chamber , the particles from the continuing flow of dust build up on the collecting plates. At periodic intervals, the plates are rapped, causing the particles to fall into hoppers. The particles are then removed from the hoppers, by a rotary screw arrangement. The Design Basis for the Electrostatic Precipitator is listed in the table below:

Volume (ACFM)	240,000
Temperature (°F)	400
H2O in flue gas (% by vol.)	15
Inlet to precipitator (gr/dscf)	2.5
Emission Rate (lbs/MMBTU)	0.025
Heat Input (MMBTU/hr)	450

Maintenance and Inspection

The air emission Electrostatic Precipitator system, and the collection systems are to be inspected daily for leakage, for defects which would affect operation, and for potential defects which would affect operation.

A daily inspection will be performed for the following:

Inspection of rapper operation
Inspection of T-R set operation
Inspection of ash removal system operation

Corrective action measures will be implemented on the occurrence of an abnormal condition. Abnormal conditions will include the following: a T-R set failure, rapper system failure, ash transport system failure, and high ash hopper level.

Each Major Unit Overhaul

Check and correct plate electrode alignment
Inspect for collection surface fouling
Inspect T-R set mechanical condition
Inspect internal structural components

Corrective action measures will be devised and implemented on the occurrence of an abnormal condition. The appropriate measures for remediation will be implemented in a timely manner.

Monitoring of Operations and Records

The operator has a graphic display for continuous monitoring of the system and trends of those operating parameter. Appropriate alarms are provided for out of range operations. All meters are set up on the mill's preventative maintenance system for transmitter calibrations. The operator has instantaneous and averaged readouts.

We will maintain a written or electronic record of all inspections and any action resulting from the inspection. Maintenance and inspection records will be kept for five (5) years and available upon request.

An audible Precipitator Malfunction Alarm is available for the operator. The precipitator malfunction alarm will continuously monitor T-R set failure and rapper control malfunction. Corrective action measures will be implemented on the occurrence of a precipitator malfunction alarm. The appropriate measures for remediation will be implemented in a timely manner.

Approximately once each month the data is automatically down loaded, consolidated into 15-minute averages and stored in the mill's data management system. The 15-minute averages are stored for 5 years

ATTACHMENT 10 - PB06 – Description of Stack Sampling Facilities

The Stack and Sampling Platforms and Ports have been designed at the submittal of this application. However, the stack sampling facilities will meet the Requirements of Appendix SS1 to the Title V Permit. The applicable portions of that document are referenced below.

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1. Sampling facilities include sampling ports, work platforms, access to work platforms, electrical power, and sampling equipment support. Emissions units must provide these facilities at their expense. All stack sampling facilities must meet any Occupational Safety and Health Administration (OSHA) Safety and Health Standards described in 29 CFR Part 1910, Subparts D and E. A permanent stack sampling facility will be installed and maintained.

2. Sampling Ports.
   a. All sampling ports will have a minimum inside diameter of 3 inches.
   b. The ports shall be capable of being sealed when not in use.
   c. The sampling ports will be located in the stack at least 2 stack diameters or equivalent diameters downstream and at least 0.5 stack diameter or equivalent diameter upstream from any fan, bend, constriction or other flow disturbance.
3. At least two sampling ports, 90 degrees apart, will be installed at each sampling location on all circular stacks that have an outside diameter of 10 feet or less. For stacks with larger diameters, four sampling ports, each 90 degrees apart, will be installed. On horizontal circular ducts, the ports will be located so that the probe can enter the stack vertically, horizontally or at a 45 degree angle.
4. On rectangular ducts, the cross sectional area will be divided into the number of equal areas in accordance with EPA Method 1. Sampling ports will be provided which allow access to each sampling point. The ports will be located so that the probe can be inserted perpendicular to the gas flow.
5 Work Platforms.
   a. Minimum size of the working platform will be 24 square feet in area. Platforms will be at least 3 feet wide.
   b. On circular stacks with 2 sampling ports, the platform will extend at least 110 degrees around the stack.
   c. On circular stacks with more than two sampling ports, the work platform will extend 360 degrees around the stack.
   d. All platforms will be equipped with an adequate safety rail (ropes are not acceptable), toeboard, and hinged floor-opening cover if ladder access is used to reach the platform. The safety rail directly in line with the sampling ports willl be removable so that no obstruction exists in an area 14 inches below each sample port and 6 inches on either side of the sampling port.
6. Access to Work Platform.
   a. Ladders to the work platform exceeding 15 feet in length will have safety cages or fall arresters with a minimum of 3 compatible safety belts available for use by sampling personnel.
   b. Walkways over free-fall areas will be equipped with safety rails and toeboards.

7. Electrical Power.

a. A minimum of two 120-volt AC, 20-amp outlets will be provided at the sampling platform within 20 feet of each sampling port.

b. If extension cords are used to provide the electrical power, they will be kept on the plant's property and be available immediately upon request by sampling personnel.

8. Sampling Equipment Support.

a. A three-quarter inch eyebolt and an angle bracket will be attached directly above each port on vertical stacks and above each row of sampling ports on the sides of horizontal ducts.

i.. The bracket will be a standard 3 inch x 3 inch x one-quarter inch equal-legs bracket which is 1 and one-half inches wide. A hole that is one-half inch in diameter will be drilled through the exact center of the horizontal portion of the bracket. The horizontal portion of the bracket will be located 14 inches above the centerline of the sampling port.

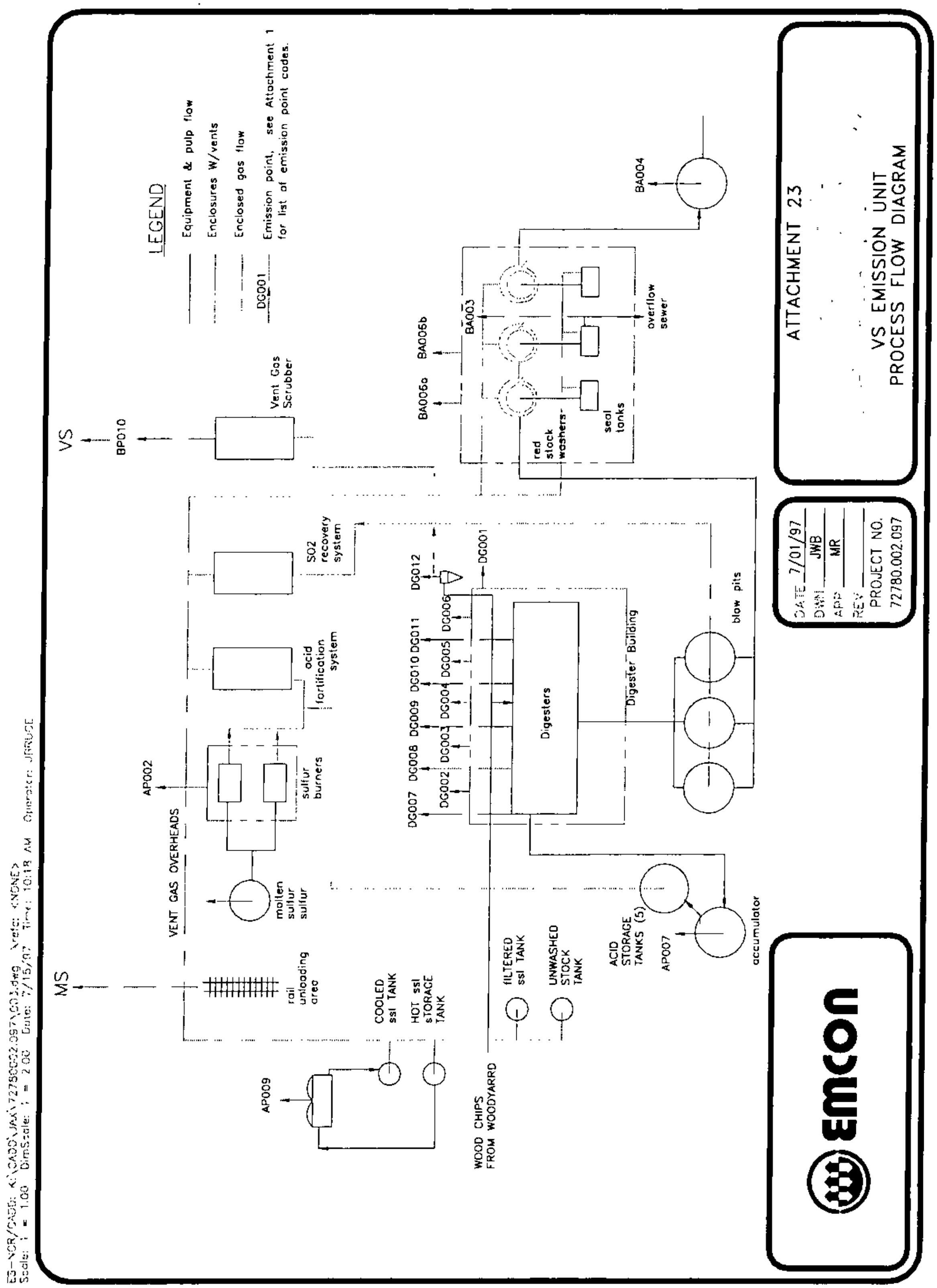
ii. A three-eighth inch bolt which protrudes 2 inches from the stack may be substituted for the required bracket. The bolt will be located 15 and one-half inches above the centerline of the sampling port.

iii. The three-quarter inch eyebolt will be capable of supporting a 500 pound working load. For stacks that are less than 12 feet in diameter, the eyebolt will be located 48 inches above the horizontal portion of the angle bracket. For stacks that are greater than or equal to 12 feet in diameter, the eyebolt will be located 60 inches above the horizontal portion of the angle bracket. If the eyebolt is more than 120 inches above the platform, a length of chain will be attached to it to bring the free end of the chain to within safe reach from the platform.

b. A complete monorail or dualrail arrangement may be substituted for the eyebolt and bracket.

c. When the sample ports are located in the top of a horizontal duct, a frame will be provided above the port to allow the sample probe to be secured during the test.
[Rule 62-297.310(6), F.A.C.]

ATTACHMENT 11 - PG Process Flow Disgram



ATTACHMENT 12 - PG Detailed Description of Control Equipment

VENT GAS SCRUBBER STACK - Digester and Washing Systems Vents

Sulfur Dioxide Control

Emissions from the cooking acid plant, the red stock washers, the unwashed stock tank, and the spent sulfite liquor tanks are collected and scrubbed in the vent gas scrubber. The vent gas scrubber consists of a packed tower containing 6 feet of poured packing. Gas flows upward through the packing. Absorbate is sprayed onto the top of the packing and continues a tortuous path downward through the packing to the bottom of the tower. Sodium bisulfite/sulfite absorbate is pumped from the tower sump to the sodium bisulfite storage tank. The loop is completed when the absorbate is pumped from the storage tank back to the top tray of the vent gas scrubber with a pH control addition of fresh caustic soda.

The liquid level in the tower sump is controlled by a PID type instrument in the acid plant distributive control system (DCS). A continuous sample of absorbate from the bottom of the tower is pumped to a pH instrument. The pH signal in the DCS controls the addition of fresh 7 percent caustic soda solution or 9 percent soda ash solution into the absorbate stream entering the top tray. The controller set point is normally pH 6.5. The pH set point may be increased to respond to an unusually high gas loading into the vent gas scrubber. The sulfur dioxide concentration in the stack is measured with a continuous emission monitor. The DCS calculates one hour, three hour and 24 hour running averages of the sulfur dioxide concentration.

Methanol Control

A trap-out ring is installed at the top of the bottom section of this tower to separate the lower sulfur dioxide scrubber from the new after condenser above. A new section containing 6 feet of packing functions as a direct contact condenser using fresh raw water. A shower distributes the fresh water over the packing. The flow of water must be once through to maintain a low enough concentration of methanol in the liquid to assure that it does not return to the gas phase. The liquid is sent directly to the sewer system and on to secondary treatment. The water addition is controlled to assure the exit gas temperature from the tower is maintained at a specified set point. This assures adequate capture of methanol by the condenser.

ATTACHMENT 5 TO APPLICATION

PROJECT DESCRIPTION
AND
RULE APPLICABILITY ANALYSIS

FOR

SIP CONSTRUCTION PERMIT FOR A NEW NUMBER 6 BUBBLING BED BOILER REPLACING ALL EXISTING POWER BOILERS,

AND

RE-EVALUATION OF THE INSTALLATION OF No. 6 DIGESTER WITH A PRODUCTION INCREASE TO 175,000 ADMT

RAYONIER PERFORMANCE FIBERS LLC
FERNANDINA BEACH DISSOLVING SULFITE MILL

Submitted
August 30, 2005

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1.0 APPLICATION DESCRIPTION

1.1 Boiler Project Description

Rayonier is planning to replace three existing power boilers at its Fernandina Beach dissolving sulfite pulp mill with one bubbling bed boiler. Self produced bark will provide most of the fuel, but knots, landscape waste and possibly a small amount of tire derived fuel will be fired at times. Minimal oil will be fired, mostly during periods when the solid fuel feed system is down. The mill has three small power boilers, all were installed prior to 1962, and therefore are not BART or NSPS eligible, nor are there NSR concerns with these boilers. Power Boiler No. 1, Title V Emission Unit PB01, is fired with residual oil only and has a heat input of 185mmBtu/hr. Power Boiler No. 2, Title V Emission Unit PB02, is fired with bark and residual oil and has a heat input of 218 mmBtu/hr. Power Boiler No. 3, Title V Emission Unit PB03, is fired with bark and residual oil and has a heat input of 245 mmBtu/hr. These boilers are aging and maintenance costs have escalated to the point where replacement is cost effective. They will be decommissioned and therefore the emissions from these boilers will be used to offset the emissions from the replacement boiler. The replacement boiler will be designated PB06.

A used traveling grate boiler will be purchased which will be converted into a bubbling bed boiler equipped with an ESP followed by an alkaline scrubber. Provisions will be made to install Selective Non-Catalytic Reduction ("SNCR") for NOX control should it be necessary to meet the emission limit proposed. It should not be needed to meet the NSPS limits as the boiler remains subject to the pre 1983 Subpart D standard as described in Section 2.0 below.

A similar conversion as successfully accomplished at Interstate Paper Company in Riceboro, Georgia. The boiler will be sized for 265,000 lbs of 900 psi steam per hour at 850 degrees Fahrenheit resulting in an annual average heat input of 450 mmBtu/hr. Occasionally heat inputs could be 525 mmBtu to partially compensate for outages of the recovery boiler, the only other steam generator at the facility. However an annual emission limit based on 450 mmBtu/hr is requested.

It will be located adjacent to the digesters east of the mill. A mill plot plan is included as Attachment 1 to the Construction Permit Application Form. Once constructed and fully operational, it will be connected to the mill steam headers. It and the recovery boiler will be the sole steam producers used by the mill. Eventually the existing boilers will be dismantled.

A newer boiler will reduce most emissions because it will have to meet more stringent New Source Performance Standards ("NSPS"), (40 CFR Part 60 Subpart D) and the recently promulgated Maximum Available Control Technology Standards ("Boiler MACT", 40 CFR Part 63, Subpart DDDDD for existing power boilers). The boiler being purchased was originally constructed in 1983. In Section 2.1 of this narrative a reconstruction analysis demonstrates this boiler has not been reconstructed. Therefore, it remains subject to the Subpart D standard, the NSPS promulgated at the time the boiler was constructed, and not Subpart Db, which applies to boilers constructed or reconstructed after July 9, 1989. Not being reconstructed also means the boiler is regarded as an existing boiler under Boiler MACT. These two rules will be discussed in greater detail in Sections 2.2 and 2.3 below.

A large electrostatic precipitator (ESP) for the removal of particulate matter followed by an alkali scrubber for the removal of SO_2 will be installed to enable the boiler to meet the new emission limits. The technology used in the boiler and its new large pollution control devices will enable compliance with the new regulations referenced above and will allow a greater percentage of bark and possibly other solid fuels such as Tire Derived Fuel (TDF) in the fuel mix.

Continuous NO_x, SO_2, flow CO, O_2 and opacity monitors are proposed for the new boiler. The monitoring to be included with this project is fully described in section 2.5.

1.2 Production Increase Project Description

This permit application also includes a production increase to accommodate the full production enabled by the installation of no. 6 digester in 1998. An industry-wide effort to inspect, repair and upgrade digesters was begun in the late 1990's following an explosion of a digester at the Stone Container Mill in Panama City, FL, now owned by Smurfit. Rayonier undertook a program to entirely reline each of its existing 5 digesters with new refractory and replace any weakened or corroded metal while it was exposed. To accomplish this Rayonier rotated a digester out of production for an extended period of time. In order to avoid lost production for orders previously taken an additional (no. 6) digester was added. Permitting of no. 6 digester was facilitated by inclusion of a production limit on the Title V operating permit of 153,205 ADMT per year. This application revisits that production limit and seeks to increase that limit to the full production capability of No.6 digester. This permitting action is more fully described in Chapter 3.0.

No changes to the mill layout are needed to achieve the production increase. Minimal additional equipment will be needed to achieve the modest production increase requested in this application. Instead of adding evaporators and the energy to run them the existing evaporators can be unloaded by concentrating some streams with non-emitting nanofiltration technology. Some additional drying capacity will be needed on the dryer section of the pulp machine. These modifications and equipment additions will take place over 5 to 10 years. Commencing construction in 18 months or 2 years is no longer a requirement as none of the changes required PSD permits which have the limit on when construction must commence. To ensure VOC emissions increases are less than the PSD Significance Level the mill will undertake a project to capture blow heat from one of the bleach plant stages that is the most significant VOC emissions source. In capturing this heat the VOCs will also be captured and sent to the biological wastewater treatment system for destruction.

1.3 Construction Permit Application Organization

Applicable regulations for each project are analyzed separately in the following two sections of this narrative statement. Because a Construction Permit can be issued faster than the simultaneous Construction and Title V permit and onsite construction must begin by November 2005, this is only a SIP construction application. After issuance of the Construction Permit, a Title V operating permit application will follow.

1.4 Schedule

Options have been secured on an existing boiler, presently configured for coal firing. Rayonier has begun engineering studies on relocating the boiler and the ancillary equipment to the Fernandina Beach mill site and replacing the coal firing equipment with a new fluidized bed for biomass fuel. These studies are expected to approach completion in September 2005. On-site work will begin late third quarter or early fourth quarter of 2005. Total installation time is expected to be about 18 months. Startup is planned for early 2007.

2.0 No. 6 BOILER PROJECT

2.1 RECONSTRUCTION ANALYSIS

In the regulatory analysis that follows it is important to determine if the boiler is considered new or existing as different emission limits apply. Simply moving the boiler does not automatically make the boiler a new boiler under either NSPS or MACT. A facility must either be constructed or modified or reconstructed to become subject to NSPS and the new source provisions under MACT. Both Title 40 Parts 60 and 63 have similar definitions of affected source and reconstruction.

Because Rayonier will invest capital to modify and replace certain boiler internals as well as move the boiler from Jacksonville to Fernandina Beach, a reconstruction analysis was performed to determine if the fixed capital costs being invested in this boiler exceeds 50 percent of the cost of a comparable entirely new facility. If reconstructed the boiler will lose its status as an existing boiler and be considered a new boiler for purposes of NSPS and Boiler MACT.

2.1.1 Reconstruction Analysis Guidance

Reconstruction is defined as the replacement of components that exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility. Both NSPS and Boiler MACT have similar definitions of reconstruction, thus only one Reconstruction Analysis is presented. The reconstruction question in the applicability requirement for both NSPS in Section 2.2 and MACT in Section 2.3 will refer back to this analysis.

EPA Applicability Determinations Index Numbers NA12, 0200048 and NB28 provide guidance for completing a Reconstruction Analysis. According to the definition one compares the fixed capital assets being invested to the fixed capital assets required for a "comparable entirely new facility" (See Reconstruction Definition 40 CFR 60.15). However, not all fixed capital assets are included in the analysis. Applicability Index NB28 states that stacks, site preparation, demolition, boiler cranes, station piping, water purification equipment, water supply systems, air cleaning systems and cooling systems and almost anything to do with a turbogenerator are excluded from the analysis. It further states that air pollution control equipment is only included if it is needed as part of the manufacturing/operating process. It would not be possible today to permit the proposed boiler without the scrubbers, ESP and stack, but this equipment is not needed for the operation of the boiler and has been excluded from the analysis. Ash handling equipment was excluded after the ash discharge valves to the ash hopper. Labor and engineering cost have been included per Applicability Determination Index Number 0200048. As Applicability Determination Index Number NB28 suggests, the units constituting the facility which are in or out of the analysis may be best represented in a diagram. Such a diagram is included in Figure 1 below.

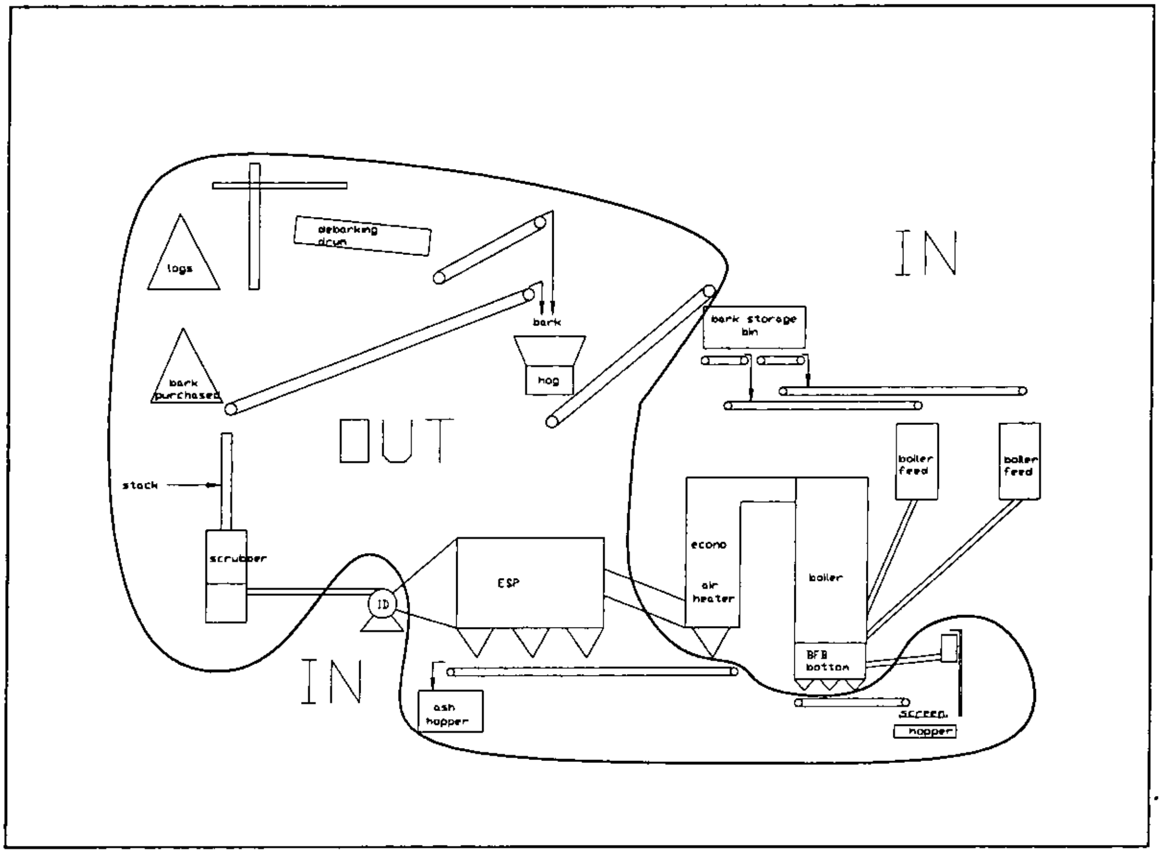

Figure 1: Extent of Reconstruction Analysis

Two approaches to estimating the cost for a comparable, entirely new facility were used. First, Rayonier was fortunate to acquire the original records for the boiler purchase and installation. These records were used to estimate the cost at the time of construction which was adjusted for those items included in and excluded from the analysis as described by EPA Guidance referenced above. These costs were then escalated to present day dollars. To this was added the new parts needed for the conversion from coal to bubbling fluidized bed.

Second, a quote for a boiler and equipment was obtained from a vendor. The quote was augmented by our engineering firm to include the foundations, buildings etc. needed to service the boiler but excluded from the vendor's quote. Both analyses are presented below.

2.1.2 Rayonier Projected fixed Capital Spending on this Project

Table 1 is Rayonier's budget for this project that has been adjusted to remove those items that are excluded from a Reconstruction Analysis according to the EPA Guidance referenced above. Total Fixed Capital Costs being invested in this project are then $13,882.000.

Table 1. No. 6 Boiler Reconstruction Analysis Fixed Capital Costs

Foundation	$ 454,000
Dismantling and Freight Costs	$ 680,000
Building Retrofitting/Re-Erection	$ 2,141,000
Boiler Pressure Parts & Installation	$ 2,459,000
Feedwater System	$ 253,000
Pressure-Part Trim	$ 250,000
Heat Exchangers	$ 1,150,000
BFB Bottom Unit	$ 1,600,000
Oil Burner Systems	$ 375,000
Sand Reclaim & Recirculation System	$ 563,000
Furnace Trim	$ 510,000
Fluidizing Air System	$ 282,000
Over-Fire Air system	$ 328,000
Gas Stream	$ 404,000
Bark Feed System	$ 401,000
Electrical	$ 1,335,000
Controls/ Instrumentation	$ 325,000
DCS	$ 200,000
Misc. Project Services	$ 172,000
TOTAL	**$ 13,882,000**

This reconstruction cost must be compared to the fixed capital costs for a comparable entirely new facility.

2.1.3 New Facility Cost Based on Escalated 1983 Costs

Rayonier was fortunate to obtain the original 1983 installation records for the used boiler being purchased. This cost information was adjusted to remove the coal burning and ash handling equipment, the pollution control equipment and the stack per EPA Applicability Determination Index No. NB28. This cost in 1983 dollars was then escalated to 2004 dollars using the Chemical Engineering Plant Cost Index ratio for the period of 1983 to 2004 of 1.40. To this cost was added the cost of the new bark handling equipment and a BFB bottom design in 2005 dollars. This analysis is presented in Table 2 below which indicates $ 39,155,000 as the cost for a comparable entirely new facility in 2004 dollars.

Table 2. Cost of a Comparable Entirely New Facility in 2005 adjusted from 1935

1983	1983 Capital Estimate	$ 29,334,000
-	Coal Handling System	$ (1,831,000)
-	Stoker Bottom System	$ (713,000)
-	Scrubber Stack	$ (974,000)
-	Dust Collector	$ (43,000)
1983	Total Boiler Cost	$ 25,773,000
2004	Adjusted Cost (Chemical Eng Plant Cost Index)	$ 36,126,000
+	Bark Storage Bin/Live Bottoms/VF Drives	$ 1,170,000
+	BFB	$ 1,600,000
+	Fluidizing Air System	$ 259,000
	COMPARABLE NEW PROJECT ESTIMATE	$ 39,155,000

Percent reconstructed = $13,882,000 / $39,155,000 = 35%

This analysis indicates that only 35 percent of a comparable entirely new facility is being spent on this project and thus it is not a reconstructed facility. Therefore, the boiler maintains its status as an existing facility as of 1983.

2.1.4 New Facility Cost Based on Recent Quote

As an alternative to the analysis presented above, the Kaverner Corporation was approached for a quote on a new comparable boiler. Their quote included air pollution control systems and stack and a complete ash system. Their quote did not include foundations, buildings, piping and electrical nor any installation costs. Projects for Industry, Rayonier's engineer for the project, then estimated, or acquired quotes for, the missing capital costs not included in the Kaverner Quote and subtracted those items not to be included per the applicability guidance sited above.

Kaverner Corp bid proposal	$ 21,136,000
Plus	
Boiler vendor erection costs	$ 11,438,000
Foundations	$ 454,000
Bark Delivery	$ 435,000
Boiler Building Steel	$ 3,100.000
Concrete Floors/Buildings	$ 670,000
Fire Protection	$ 160,000
Boiler Utilities Piping	$ 260,000
Electrical	$ 2,400,000
DCS System	$ 650,000
Engineering	$ 1,500,000
Site Services	$ 172,000
Minus	
ESP	$ 1,930,000
150 foot stack	$ 180,000
Ash system	$ 186,000
SNCR equipment in vendor quote	$ 265,000
Grand Total Comparable Entirely New	**$ 39,814,000**

Estimated Cost of project from Table 1 $13,882,000

Percent reconstructed = $ 13,882,000 / $39,814,000 = 35%

2.1.5 Rule of Thumb Estimation of New Boiler Costs

Boiler manufacturers through experience have developed 'rules of thumb' for estimating costs for new boilers. Generally $150,000 per 1000 pounds per hour of steam capacity is used for estimating the capital cost of similar high pressure boilers. Using this method a similar all new boiler would cost $39,750,000 which compares favorably with the estimates arrived at by the two specific methods above.

It must be remembered that all three of these approaches represent estimates only. Generally the estimates are high to allow for some unforeseen difficulty such as equipment defects, weather delays, delays in delivery of needed parts etc.

2.2 BOILER NEW SOURCE PERFORMANCE STANDARDS

2.2.1 40 CFR Part 60 Subpart D, Da and Db Boiler Applicability

The Federal New Source Performance Standards (NSPS) authorized by Section 111 of the Federal Clean Air Act are found in 40 CFR Part 60. Subpart D of Part 60 applies to steam generators (boilers, especially those using fossil fuel) and was adopted in June 14, 1974 applying to boilers constructed or reconstructed after August 17, 1971. (NSPS is somewhat unique in that it begins applying to sources when proposed and not beginning with final promulgation.) Subpart D was in effect at the time this boiler was constructed and applied to this boiler when constructed.

Somewhat later in June 11, 1979 Subpart Da, was adopted and applied to electric utility steam generators constructed or reconstructed after September 18, 1978. An electric utility steam generator is defined as one selling more than 25 megawatts or one third of the electrical power generated. The mill has the ability to sell electricity to the grid, but Rayonier will not sell more than 25 megawatts nor will it sell one third of the generating capacity of the mill or about 15 megawatts. Subpart Da does not apply to this project.

Subpart Db applies to Industrial, Commercial and Institutional boilers having greater than 100 mmBtu/hr heat input constructed or reconstructed after June 19, 1984 and was adopted in December 16, 1989. This boiler was constructed before June 19, 1984 therefore Subpart Db does not apply, unless the boiler is considered reconstructed or modified. If the boiler were considered reconstructed or modified Subpart Db would apply and not Subpart D.

2.2.2 Is the Boiler Reconstructed Under NSPS?

The Reconstruction Analysis presented in Section 2.0 demonstrated that the work planned by Rayonier does not trigger reconstruction.

2.2.3 Is the Boiler Modified Under NSPS?

The 40 CFR Part 60 regulations define modification as any action resulting in any increase for any pollutant for which there is a standard. As the new owner Rayonier has no knowledge of previous emissions of this boiler. Therefore, its emissions have been estimated at the previous permit limits. It is reasonable to expect this boiler was operated close to its limits as pollutant removal equipment as was used to achieve them. Pollution control equipment enables close control of ultimate emissions and it is reasonable to expect that those controlled emissions were close to the limits. Indeed 40 CFR 60.8 requires operation at the maximum rate of production before a compliance test for NSPS can be run. This maximum rate of operation is limited by NSPS.

The emission limits imposed by the 40 CFR Part 60, Subpart D in 1983 are presented in Table 3 below. Table 3 also presents the expected new limits. All of the new limits are equal to or less than the old limits. Therefore the relocation and reengineering of this boiler is not considered a modification.

The mandatory scrubbing of SO_2 to achieve an additional 90% reduction had not been adopted in 1983. However, because this boiler burned coal, scrubbing for SO_2 and for NO_x was mandatory to meet the NSPS limits. Scrubbing is not mandatory to meet the limits when the fuel consists mostly of bark with some liquid fossil fuel (No. 6 oil).

Table 3. 40 CFR Part 60 Subpart D limits in 1983

Pollutant	Limit in lbs/mmBtu unless indicated	Expected New Limit in lbs/mmBtu unless indicated
PM	0.1	0.07
Opacity	=<20% except 6/hour<27%	=<20% except 6/hr<27%
SO2 solid fossil fuel	1.2	NA
SO2 liquid fossil fuel	0.8	0.8
NOx	0.3	0.3[1]

[1]For NSR purposes the facility will be accepting a lower limit for NO_x.

Emissions from the boiler after installation will not be greater than those before this project as listed in Table 3. Therefore no modification has taken place and the boiler maintains its classification as an existing boiler under 40 CFR Part 60 subpart Db and constructed after June 14, 1974 and before June 19, 1984 and remains subject to the limits in Subpart D.

2.3 BOILER MACT STANDARD APPLICABILITY

2.3.1 40 CFR Part 63, Subpart DDDDD

EPA promulgated 40 CFR Part 63, Subpart DDDDD in the September 14, 2005 Federal Register with a compliance date of September 13, 2007 for existing boilers and upon startup for new boilers. This rule imposes MACT (Maximum Achievable Control Technology) limits for Hazardous Air Pollutants (HAPs). Particulate Matter is used as a surrogate for the 8 metal HAPs that are the target of the standard. An alternative standard is provided allowing a facility to choose whether it is to be limited by total particulates or a limit for the 8 metal HAPs. Boiler MACT also limits mercury and hydrogen chlorine emissions from all boilers and carbon monoxide emissions are limited from new boilers only. See Table 4 below.

Table 4. 40 CFR Part 63, Subpart DDDDD Limits For Existing Boilers

Pollutant	Limit - Existing
Particulate	0.07 lb/mmBtu
8 metal HAPs	0.001 lb/mmBtu
Hydrogen Chloride	0.09 lb/mmBtu
Mercury	0.000009 lb/mmBtu
Carbon Monoxide7	None
Opacity	None if wet scrubber Use ESP parameters

2.3.2 Is No. 6 Boiler Reconstructed Under Boiler MACT

If sufficient capital is invested in changes to an emission unit it may be reconstructed. Similar to NSPS, if reconstructed, it is considered new. Part 63 (MACT) and Part 60 (NSPS) use the same definition for reconstruction. The General Provisions of Part 63 were amended on April 5, 2002 to clarify that relocated existing sources retain their existing source status (absent reconstruction) and do not become subject to new source MACT.

The reconstruction analysis for the boiler was presented in section 2.0 above. This boiler has not been reconstructed. It was originally constructed in 1983 and unless considered modified is subject to the existing boiler Subpart DDDDD standards.

2.3.3 Is No. 6 Boiler Modified Under Boiler MACT

The MACT standards do not define a modification. A facility is constructed or is reconstructed after promulgation and therefore it is a new source, otherwise it is an existing source. The boiler is not reconstructed (See Section 2.0) The MACT limits for existing boilers apply to this boiler.

2.3.4 Will No. 6 Boiler meet new Boiler MACT Limits

An existing boiler must comply with the limits in Table 5 by September 13, 2007. The facility then has 180 days to prove compliance by testing. At least 60 days prior to the compliance performance test, a Site Specific Monitoring Plan must be submitted. The Site Specific Monitoring Plan must state the limits, how the facility will demonstrate compliance with the limits and how they will be monitored on an on-going basis. It is early to provide such a Monitoring Plan as there is no experience with the reconfigured boiler. It is not required at this time because this is regarded as an existing boiler. A Monitoring Plan will be provided prior to May 2008, six months following the compliance date. This boiler is not scheduled to commence operation until early 2007.

The ESP is designed to meet the particulate limit of 0.07 lbs./mmBtu with some margin of safety. Since there is a wet alkali scrubber following the ESP prior to the stack, the opacity limits do not apply.

An attempt will be made to use the fuel analysis option to demonstrate ongoing compliance as allowed by the rule. In this option a facility is allowed to demonstrate that it meets the rule if all selected metals listed in the rule found in a worse case fuel mix are assumed to be emitted at a rate less than the limit. At the very minimum the fuel analysis option will be used for mercury and hydrogen chloride compliance. If the fuel analysis option is used, a Fuel Analysis Plan is required to be submitted at least 60 days prior to beginning the fuel analysis. Anticipated emissions are given in Table 5 below along with the limits for existing boilers. The analysis of available data from the literature for mercury and chlorine in fuels is included in Table 6 below. This demonstrates that even with Tire Derived Fuel, the Fuel Analysis Option will demonstrate compliance with the mercury and hydrogen chloride limits.

Table 5. Boiler MACT and Expected Emissions from No. 6 Boiler

Pollutant	**Boiler MACT Limits**	**Predicted Emissions Boiler MACT Pollutants**
Particulate	0.07 lb/mmBtu	0.07 lb/mmBtu
8 metal HAPs	0.001 lb/mmBtu	unknown
Hydrogen Chloride	0.090 lb/mmBtu	0.019 lb/mmBtu
Mercury	0.0000090 lb/mmBtu	0.0000016 lb/mmBtu
Carbon Monoxide	None	<400 ppm @ 7% O_2 30 day average
Opacity	None if wet scrubber Use ESP parameters	None – wet scrubber

Table 6. Boiler MACT Analysis for HCl and Hg Compliance.

BOILER MACT FUEL ANALYSIS								
	%	**Ton/hr**	**Btu/lb**	**HCl (lb/mmBTU)**	**mmBTU/hr**	**lb. HCl/hr**	**Hg (lb/mmBTU)**	**lb. Hg/hr**
Bark	70	36.0	5,100	0.0103	367.2	3.78210	0.000001420	0.000521424
TDF	10	2.5	15,500	0.0730	77.5	5.65750	0.000003720	0.000288300
#6 Oil			18,000	0.0075	0.0	0.00000		0.000000000
Lndscp Wst	10	5.0	5,100	0.0070	51.0	0.35700	0.000000451	0.000023001
Knots	10	3.5	4,300	0.0070	30.1	0.21070	0.000000451	0.000013580
TOTAL					525.8	10.00736		0.000846300
				<u>HCl</u>			<u>Mercury</u>	
Actual				0.0190 lb/mmBTU			0.0000016 lb/mmBtu	
Limit				0.0900			0.0000090	

If the option for the alternate limit for selected metals cannot be used, ESP field parameters ranges will be developed during initial compliance testing and will be used as surrogate parameters to monitor compliance. A wet alkali scrubber, installed primarily for sulfur dioxide control, will also capture hydrogen chloride.

2.4 NSR APPLICABILITY TO THE BOILER PROJECT

2.4.1 Existing Emissions

Except for NOx emissions, Table 7 below presents the latest five years of annual emissions as reported in the Annual Operating Report ("AOR") submitted to the Department annually every March 1. Over the years the basis for calculating emissions has changed for some pollutants and those changes are documented in Appendix A. Baseline periods comprising two consecutive years are averaged for each pollutant. Generally the two consecutive years of maximum production have been averaged to determine baseline emissions, as we believe these years are most representative of normal operations. However, a 2004 test for CO indicated lower emissions than predicted from emissions factors and thus a later 2003-2004 baseline is used. The SO2, NOx and VOC baseline was selected to reflect the maximum oil usage as it is the major source of these emissions. The NO_x emissions have been changed from the AOR as further described below. Baseline years have been selected to reflect what the facility actually emitted in the recent past using the best data available. The facility makes many different grades of pulp, each having its own emission characteristics. Generally the highest emissions are selected so that the facility will not be restricted as to the grade of pulp it can manufacture.

Table 7. TPY Emission of Boiler Relevant Regulated Pollutants last 5 years

Year	2004 TPY	2003 TPY	2002 TPY	2001 TPY	2000 TPY	Baseline years	Avg. Baseline years
PM	220.29	176.39	258.35	235.14	316.98	00-01	276.06
PM 10	195.37	156.24	228.95	208.40	276.56	00-01	242.48
SO_2	99.33	130.31	171.21	192.70	162.73	01-02	181.96
NO_x	298.80	328.75	336.91	345.00	*	01-02	340.95
CO	647.14	734.35	780.72	805.89	855.46	03-04	690.75
VOC	42.78	48.66	51.58	53.21	23.97	01-02	52.40

*A steam measurement for this year was not available for calculating annual NOx emissions.

In previous AORs the NO_x emission was calculated using AP42 Emission Factors. These factors indicate NOx varies with oil fired as well as other boiler characteristics. The mill has two boiler stacks each equipped with a venturi scrubber. Power boiler Nos. 1 and 2 both vent to the stack and venturi scrubber designated A. Power boiler No. 3 vents to stack and scrubber B. A total of 14 tests for NO_x have been conducted on the 2 stacks. Figure 2 demonstrates the relationship between oil fired and NO_x emissions. Stack tests of both boiler stacks determined there were fewer NO_x emissions than reported in the AOR.

No. 1 boiler is fired with oil only. Nos. 2 and 3 boilers are fired with a mixture of oil and waste wood, generally bark. Most stack tests are focused on particulate emissions and thus are run with a minimum of oil and a maximum of bark, which minimizes the NO_x emissions. Numbers 1 and 2 power boilers are always fired with a high percentage of oil because Number 1 power boiler is only oil fired. Fuel records show that on an annual average about 62 percent of the heat input is from oil for No. 1 and 2 boilers and 17 percent for No. 3 boiler. From Figure 2, the NOx emission rates for the A stack are 0.2 lbs/mmBtu based on recent tests and for B stack is 0.1623 lb NO_x/mmBtu.

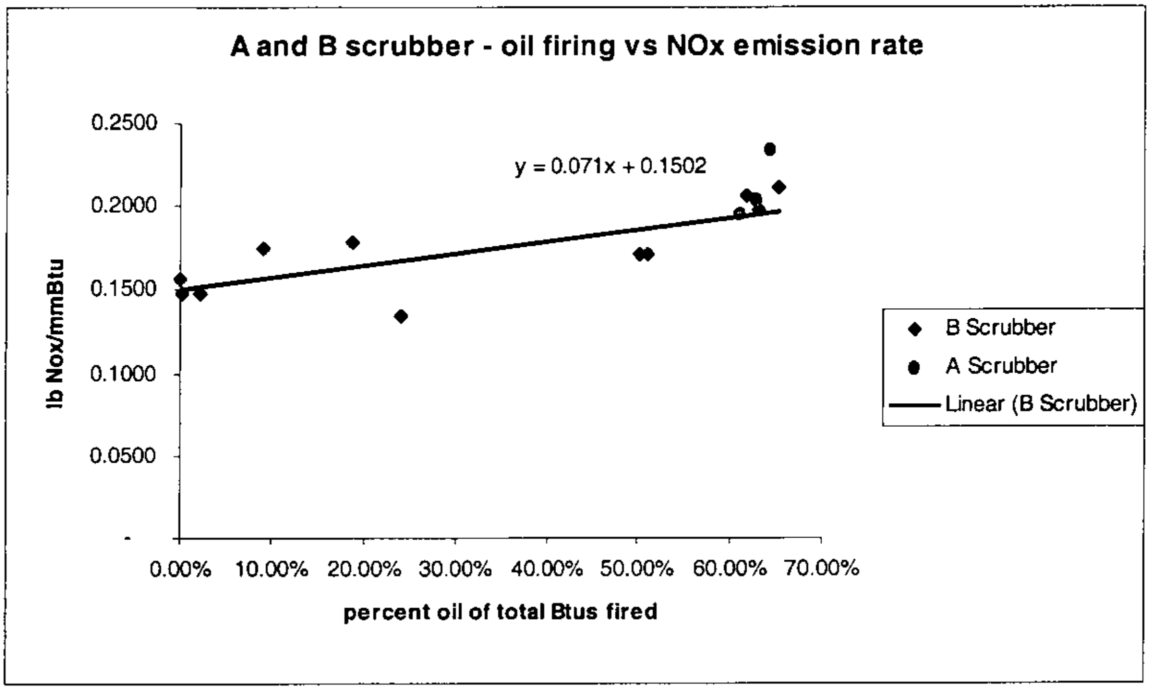

Figure 2 Tested NO_x Emissions versus Percent Oil in Fuel Fired

Efficiencies for each boiler during the fourteen tests for NO_x presented above were examined. Annual steam production for each boiler from 2001 through 2004 was also examined. Heat inputs were calculated from F-factors as were NO_x emission rates. Table 8 presents the steam made during each test and the heat input so that an efficiency is calculated. This efficiency is used to calculate the heat input for annual steam production, and using the NO_x emission rates from Figure 2 annual NOx_x emissions are calculated for each year for which there are accurate steam measurements – 2001through 2004. The adjusted NO_x baseline of 340.95 is presented in Table 7 and in Table 9 as the average of emissions in years 2001 and 2002, the two consecutive highest years.

Table 8. Efficiency of Boiler during Test

Date	Test Run	Time Begin	Time End	Scrubber	Heat in Steam Produced during Test mmBtu/hr	Heat Input from F-Factor mmBtu/hr	Efficiency	Average Efficiency
6/10/2004	1	12:00	13:00	A	176.00	270.42	65%	
6/10/2004	2	14:41	15:41	A	170.46	265.42	64%	
6/10/2004	3	17:34	18:34	A	169.91	252.65	67%	66%
6/9/2004	1	12:27	13:56	B	126.07	278.62	45%	
6/9/2004	2	15:00	16:39	B	122.52	228.92	54%	
6/9/2004	3	17:51	18:51	B	113.52	232.76	49%	
7/8/2005	1	8:59	9:59	B	112.28	216.55	52%	
7/8/2005	2	10:22	11:22	B	110.28	214.80	51%	
7/8/2005	3	11:38	12:38	B	110.14	227.54	48%	
7/8/2005	4	13:58	14:58	B	134.81	254.76	53%	
7/8/2005	5	15:09	16:11	B	136.07	261.30	52%	
7/14/2005	1	9:00	10:00	B	123.39	236.25	52%	
7/14/2005	2	10:17	11:17	B	119.18	223.11	53%	
7/14/2005	3	11:37	12:37	B	133.69	238.51	56%	51%

The average efficiency for A stack, Nos. 1 and 2 boilers, is 66% and for B stack, No. 3 boiler, is 51%.

Table 9. Annual NO_x Emissions Recalculated

Boiler	Energy in Steam Produced mmBtu/yr	Efficiency	Annual Heat Input mmBtu/yr	NO_x Emissions
2001				
				TPY
A	1,284,146.99	66%	1,959,978.25	196.00
B	944,517.56	51%	1,836,189.02	149.01
Total				**345.00**
2002				
A	1,284,167.28	66%	1,960,009.22	196.00
B	893,189.45	51%	1,736,404.63	140.91
Total				**336.91**
2003				
A	1,189,099.78	66%	1,814,908.83	181.49
B	933,427.43	51%	1,814,629.26	147.26
Total				**328.75**
2004				
A	1,121,154.39	66%	1,711,204.59	171.12
B	809,314.27	51%	1,573,347.12	127.68
Total				**298.80**

2.4.2 Emission Increases/Decreases due to No. 6 Boiler

Section 2.2 discussed the applicability of the Federal New Source Performance Standards (NSPS) that apply to the boiler, found at 40 CFR Part 60 Subpart D. Table 3 presented the applicable emission limits. Section 2.3 discussed the Boiler MACT Standards found at 40 CFR Part 63, Subpart DDDDD. Table 4 presented the applicable emission limits of this standard.

In reviewing the projected emission rates based on the two applicable emission standards, NSPS and Boiler MACT, and comparing potential emissions to the baseline emission in Table 7 it was determined that NO_x and SO_2 annual emissions will exceed the PSD Significance Levels. Annual emissions from all other pollutants will decrease. In order for this project to avoid PSD permitting the facility is willing to accept a NO_x emission limit of 379.95 tons per year annual average and a SO_2 emission limit of 220.95 tons per year annual average. This emission rate is based on 8760 hours per year operation.

Table 10. No. 6 Power Boiler Emissions

Pollutant	Source of limit	Emission rate lb/mmBTU	Potential Emission ton/year	Baseline Emissions ton/yr	Emission Change ton/yr	PSD Significance Level
PM	Boiler MACT	0.07	138	276.06	(138)	25
PM10	PM as PM10	0.07	138	242.48	(105)	15
SO_2	ESCPSD	0.1121 ann. avg.	220.95	181.96	39	40
NO_x	NSPS	0.1928 ann. avg.	379.95	340.95	39	40
CO	None	- 0.2 -	99	690.75	(591)	100
VOC	None	- 0 -	- 1 -	52.40	(45)	40

2.5 *EMISSION MONITORING FOR No. 6 BOILER*

2.5.1 Emission Monitoring Required by NSPS

40 CFR 60.45, the specific regulation requiring monitors for boilers subject to Subpart D requires the installation of Opacity, SO_2 and NOx monitors along with either O_2 or CO monitors and the capability of converting the continuous emissions monitoring data to lb/mmBtu units. The boiler will be equipped with CEMs for SO_2 and NO_x meeting Performance Specifications 2 and 3 found in Appendix B of that Part. Both an oxygen monitor and a carbon monoxide monitor will be used, though the carbon monoxide monitor is not required. Because this boiler will have a final alkali scrubber just before the stack, the opacity monitor will be installed after the ESP and before the scrubber. How this will effect compliance determinations is yet to be determined.

2.5.2 Emission Monitoring Required by Boiler MACT

Boiler MACT requires opacity monitors on a dry stack, but this boiler will be equipped with a final alkaline scrubber, making a wet plume on which opacity monitors can not be used. As stated above, an opacity monitor will be located between the ESP and the scrubber. However, provisions will also be made for continuous monitoring of the field amperage and voltage on the ESP and pressure drop and flow on the final scrubber should it be required because the fuel analysis option in boiler MACT is not available.

2.5.3 Monitoring Required to Track NSR Requirements

The mill is proposing a CAP on NO_x and SO_2 emissions less than the limit allowed by NSPS. This CAP is on an annual basis, not to exceed an annual average NO_x emission of 394.74 tons per year and an annual average SO2 emissions of 220.95 tons per year. The NO_x monitoring equipment installed to meet the NSPS requirements above will accumulate continuous NO_x data on a lb/mmBtu basis. Running annual averages will be available daily. This is appropriate because the CAP is taken to avoid PSD which measures significance in terms of annual emissions. Other regulations require NO_x monitors. This monitoring will also require monitoring stack gas flow. Gas flow will be monitored by an ultrasonic type flow monitor so that flow can be continuously determined to calculate annual NO_x and SO_2 emissions.

3.0 PRODUCTION INCREASE FOR No 6 DIGESTER

As described in the Introduction in Chapter 1.0, the mill accepted a production cap to facilitate the installation of an additional digester. At the time, extensive inspections and maintenance was required on all digesters in the industry following the loss of a digester at another pulp and paper mill in Florida. Inspections and rebricking of each digester involved outages that would have interrupted production and delayed order delivery to customers. To avoid possibly losing customers the mill quickly added no. 6 digester to the 5 existing digesters so that one could be out-of-service and the same number still function. Thus enabling the mill to maintain the planned level of production for the year to match sales.

Soon all digesters will be repaired. Improvements in market position have created an opportunity to make use of some of the production capability the added digester enabled. Full utilization of the digester would achieve 175,000 ADMT per year or about 16.7 percent increase over that baseline 1996 production (149,957 ADMT). This production rate increase is driven mainly by an increase in market demand. Several market changes have caused an increase in demand for our product. Most importantly a major competitor has closed its mill in Mississippi and left the dissolving pulp business. Some of those customers are now buying pulp from this facility. As the price of petroleum increases there is an increase in demand for plastics from cellulose. Finally, markets for some new electronic products that use pulp produced by this facility are increasing. It is essential that the mill move now to meet this demand growth to keep its customers, meet growing foreign competition and maintain domestic jobs.

There is no New Source Performance Standard that applies to sulfite mills. 40 CFR Part 63, Subpart S, the Pulp and Paper MACT standards, does apply to sulfite mills. Under this standard there are slightly different standards for new and existing sources. Modifications are not included in the rule. Sources are either new, being constructed or reconstruction, or are existing sources. A reconstruction analysis is addressed but because one digester compared to the rest of the pulping segment is small a complete reconstruction analysis was not completed.

40 CFR 52.21(r)(4) requires that once a source has taken limit to avoid PSD permitting it must review the permit as if the construction has not occurred. Because emission reductions pursuant to Part 63, Subpart S were mandated a revised baseline of 2002/2003 was used to calculate what actual emissions increase would be as a result of the production increase. To comply with 40 CFR 52.21(r)(4) the same 1996 baseline production rate was used similar to the 1998 original digester permit but emissions rates from 2002/2003 were used and increased on a percentage basis to account for the production increase.

This production increase project is entirely separate from the power boiler project. These two projects are combined in this application to minimize application review time and eliminate duplicative application processing. As will be shown under the power boiler and recovery boiler discussion in subsection 3.3.1 and 3.3.2 below, the existing power boilers and the recovery boiler both have the ability to produce the steam needed for this production rate, and can therefore be excluded from this analysis pursuant to 40 CFR 52.21(b)(ii)(c).

3.1 METHOD OF OPERATION AND EQUIPMENT CHANGES

The mill will not change its method of operation. It will of course change the rate of operation of the existing equipment. All of the pulping and bleaching emissions increases and decreases are accounted for in Table 13. Although the mill can produce more pulp than the present limit without any additional equipment, some additional equipment and upgrades to existing equipment will be required to achieve the 175,000 ADMT rate. The emission increases from all of this equipment is accounted for in Table 13. The following equipment will be added in approximately the following order: numerous upgrades on the existing pulp machine (none will increase emissions and most involve increasing the steam pressure in the drying section and increasing the lineal machine speed), an additional post HCE washer, installation of nanofiltration of certain streams to recover caustic and relieve the evaporators of evaporating the caustic liquors so they can be dedicated to evaporating red liquor, a new HCE cell in addition to the 8 existing cells (this will be controlled as part of the HCE blow heat recovery system), a new pre HCE thickner and possibly a new ClO_2 tower.

The production increase will increase VOC emissions, most of which come from the HCE blow gases. This production increase includes a project to install heat recovery of the hot gases blown from the HCE cells. These are similar to kraft digesters but do not use sulfur compounds in the reaction process and therefore do not have the TRS gases. Emissions are steam and VOCs, mostly methanol. Blow heat recovery will cool these gases until most of the VOCs condense. The heat will be used elsewhere in the process and the captured VOCs will end up in the wastewater treatment system. Predicting the exact capture at the HCE blow heat recovery system and the escape using WATER9, at the treatment system is extremely difficult. More than 75% of the bleach plant emissions come from this source. This analysis conservatively assumes that only 50% of those emissions will be captured and destroyed in the wastewater treatment system.

3.2 RECONSTRUCTION ANALYSIS

A detailed reconstruction analysis similar to that presented for No. 6 boiler is not needed. No. 6 digester is part of a very large digester system that includes blow tanks, heat exchangers, and columns for the capture and reuse of SO_2. Only the digester itself is new, but it cannot function without the rest of the system. Furthermore, The Subpart S MACT standards apply to the entire pulping and washer lines, in fact to the whole mill. It should be immediately obvious that the capital cost of adding one digester does not approach 50% of the cost of replacing the entire pulping line let alone the mill.

3.3 DIGESTER NEW SOURCE PERFORMANCE STANDARDS

There are no NSPS standards that apply to sulfite mills.

3.4 PULPING MACT 40 CFR PART 63 SUBPART S

EPA promulgated 40 CFR Part 63, Subpart S in the April 15, 1998 Federal Register with an effective date of April 15, 2001. This rule applies to kraft, sulfite and other wood pulping processes and establishes a limit on the VOC HAPs from digester systems, pulp washing systems and liquor recovery systems, and waste water treatment systems (if used as the method to achieve the limits). Methanol is used as a surrogate. For sulfite mills total methanol emissions may not exceed 2.2 pounds per oven dry unbleached short ton of chemical pulp produced.

The existing digester system at this facility was required to meet the limits in 40 CFR Part 63, Subpart S by April 15, 2001. Rayonier Fernandina Beach Mill chose to install direct contact methanol condensers on the emission point venting the combined digester and washing systems, on the vent for the evaporator non-condensables and to use biological treatment to destroy the VOC HAPs (methanol) collected in the water used in the condensers. Reported elsewhere are the results of numerous annual tests demonstrating that the mill meets the Subpart S MACT standards.

Both the digester/washer system condenser and the evaporator system condenser are sized to operate at full capacity of both systems. Both condensers are capable of handling the increased methanol loading and maintaining present methanol emission levels. The recovery boiler, the largest source, has tested in compliance at the increased production operating rate. More condenser water may be used and that has not been finally quantified. At the higher production rate new parameter curves will be produced and submitted as part of the continuing Compliance Methodology, now part of the renewed Title V permit for the mill.

In any event the mill will remain subject to the Subpart S MACT limit of 2.2 lbs of methanol per Oven Dry Unbleached Short Ton of pulp produced. The point is that no changes to the existing control equipment will be necessary to maintain compliance.

3.5 NSR APPLICABILITY

Because the addition of No. 6 digester avoided PSD in 1998 by accepting a production limit as a surrogate to limiting emissions, 40 CFR 52.21(r)(4) applies and requires a review of PSD as if the No. 6 digester has not yet been installed.

> (4) At such time that a particular source or modification becomes a major stationary source or major modification solely by virtue of a relaxation in any enforceable limitation which was established after August 7, 1980, on the capacity of the source or modification otherwise to emit a pollutant, such as a restriction on hours of operation, then the requirements or paragraphs (j) through (s) of this section shall apply to the source or modification as though construction had not yet commenced on the source or modification.

To satisfy the 40 CFR 52.21(r)(4) requirement, this analysis used the same baseline production used in 1998 for the original PSD analysis for No. 6 digester. The baseline production for No. 6 digester analysis was the 1996 net production of 149,957 ADMT. A production increase to 175,000 ADMT/yr represents a 16.70 percent increase. Emission changes are calculated as a percentage of the increase in production over that used for the analysis for No.6 digester. Each relevant pollutant for each emitting mill segment has baseline emissions determined based on 2002/2003 emissions and those emissions are increased by 16.70 percent. The increase is compared to the Significance Level. If the increase is less than the Significance Level no PSD review is required for that pollutant.

Baseline emissions have been taken from the Annual Operation Report and are presented in Table 11 below. Previous reported emissions for VOCs, except for 2002, contain emissions now required to be controlled and therefore were not used to develop the baseline. The MACT Subpart S standards were complied with in April 2001. Reported emissions after this point include the required emission reductions.

There are five mill segments that have emissions, the power boilers, the recovery boiler, the pulping system vent (vent gas scrubber), the bleach plant vents and the evaporator system vent. As will be demonstrated below the existing power boilers and recovery boiler have the capability to achieve and have achieved operation rates consistent with the 175,000 ADMT production rate and will not only be increasing their rate of operation and thus are exempt from the this PSD review. The pulping segment, the bleach plant and the evaporators are being debottlenecked and these segments are analyzed for emissions increases.

3.5.1 Recovery Boiler

The recovery boiler is permitted at an operating rate of firing 70,000 lb of red liquor solids per hour. It has operated at this rate from time to time and has been repeatedly tested at this rate. It has therefore shown itself capable of operating at this rate. It does not on average operate at this rate because of market conditions. Nevertheless, 40 CFR 52.21(b)(41)(ii)(c), recently adopted revisions to the New Source Review applicability determinations, specifically allows the exemption from projected actual emissions increases in emission that could have been accommodated.

> 40 CFR 52.21(b)(41)(ii)(c) .....Shall exclude, in calculating any increase in emissions that results from the particular project, that portion of the unit's emissions following the project that an existing unit could have accommodated during the consecutive 24-month period used to establish the baseline actual emissions under paragraph (b)(48) of this section and that are also unrelated to the particular project, including any increased utilization due to product demand growth;

It should be noted that this has been the law since the WEPCO (893 F2nd 901, 1990) which involved a utility boiler and EPA has merely recognized this by expanding the demand growth concept to cover industrial boilers in the new regulation cited above. The recovery boiler could have accommodated the operating rate of 70,000 lbs/hr. The permitted firing rate is 70,000 lbs/hr red liquor solids and it has been tested at that rate. The most recent performance tests for methanol compliance in May 2004 are presented in Table 11 below. The mill assured the methanol capture system for the evaporators was adequately designed for this rate and for each methanol compliance test both the boiler and evaporators were operated at the 70,000 lb/hr rate. No capital expenditure was needed to operate the recovery boiler at 70,000 lbs./hour, and this increase in the rate of production is purely driven by market demand. Therefore, pursuant to 40 CFR 52.21(b)(41)(ii)(c) the emission increases from the recovery boiler that will be experienced by a physical change (the added digester) will not be included in the calculation of whether any increase in emission attributable to the production increase exceeds the Significance Level.

Table 11. Recovery Boiler and Evaporator Operating Rates During Tests

Test Date and Time	Solids to Recovery Boiler lb/hr	Solids to Evaporators lbs/hr	Test Date and Time	Solids to Recovery Boiler lb/hr	Solids to Evaporators lbs/hr
9/18/1996	70,399	No evaporator data recorded during these tests	5/7/2002	66,375	
	68,580			64,162	
	73,411			65,192	
9/18/1996	71,538		4/14/2003	62,954	
	69,905			65,603	
	67,551			69,677	
9/8/1998	64,777			69,257	
	61,164		4/15/2003	69,489	
	62,005		5/20/2004	69,000	70,000
11/2/1999	65,697			70,000	70,000
	64,619			70,000	70,000
	64,447		5/21/2004	68,000	72,000
4/5/2000	61,429			68,000	72,000
	63,299			67,000	69,000
	62,756		5/24/2004	70,000	71,000
5/1/2001	65,881				
	64,473				
	61,706				

2003-2004 (4) tests

68,425

68,425/70,000 = 99.14%

3.5.2 Power Boilers

It has already been shown from the above application regarding the new power boiler that even at full potential operating rate the boiler does not trigger PSD. Pursuant to 40 CFR 52.21)(b)(41)(ii)(c) it is necessary to demonstrate that the existing boilers as well as the boiler replacing them has the capability to support the projected market demand and need not be included in the emission increase calculus. Table 12 presents data to demonstrate that the existing power boilers have the capability as well as the rated capacity to operate at the 265,000 lbs of steam per hour rate. It is worth note that this Table also demonstrates why the two projects covered by this application are separate and completely unrelated because this table shows that the production increase could be accomplished without the installation of No. 6 boiler.

Table 12. Annual Average Steam Production by Boiler (thousands of pounds)

Boiler	Capacity KLb Steam/hr	1998	1999	2000	2001	2002	2003	2004
1	120	89	85	69	74	80	74	59
2	120	82	107	74	80	80	76	69
3	135	106	109	107	114	106	108	92
Total	375	278	302	240	268	266	259	220
Production ADMT/yr		132,016	119,689	151,515	146,247	145,895	144,976	145,883

Table 12 demonstrates that not only do the existing power boilers have the permitted capacity, but have operated at rates exceeding the rate being permitted in Power Boiler Number 6. It also demonstrates the successful efforts made by the facility to improve the energy efficiency as more pulp is made with less energy. One of the benefits of the project to capture the HCE blow gas heat, in addition to the reduction in VOC emissions, will be to capture more lost heat to further improve energy efficiency.

3.5.3 Pulping System Vent (Vent Gas Scrubber)

Sulfur dioxide and VOCs are the two pollutants having applicable PSD significance levels emitted from this collection of emission units associated with pulping and washing.
Table 13 below presents annual sulfur dioxide and VOC baseline emissions and the calculated increase from the production increase.

3.5.4 Bleaching System Vent

Both VOCs and Carbon Monoxide (CO) from the use of ClO2 bleaching are emitted from this source. The VOC emissions have been taken from the Annual Operating Report. The CO emissions have been calculated using NCASI Technical Bulletins No. 701 Compilation of Air Toxic and Total Hydrocarbon Emissions for Sources at Chemical Wood Pulp Mills, and No. 760, "Carbon Monoxide Emissions from Oxygen Delignification and Chlorine Dioxide Bleaching of Wood Pulp".

VOC emissions have been calculated using testing of certain high VOC emitting stages and trade association emission factors. Over 80% of bleach plant VOCs come from one specific stage and most of this is methanol. This stage involves a cooking process, after which the pulp is blown to a tank that is vented to atmosphere. The heat is wasted. This application involves the installation of a blow heat recovery system that will also capture methanol other VOCs with similar or higher boiler points. It is estimated that 50% of the methanol would be captured by this project. Other methanol control systems using similar processes, direct contact condensation and closed conveyance systems achieve much greater reductions, so this estimate is considered conservative.

A production increase to 175,000 ADMT would cause VOC emissions to increase more than the PSD Significance Level. However, a production increase to 162,000 would clearly not as it is only an 8% increase and the 8% increases of all related emissions does not cause the total emissions increase to exceed the PSD Significance Level This is shown on Table 13 as the 8% increase. However, with the above mentioned project VOC emissions will decrease even with the production increase to 175,000 ADMT/yr. This application is requesting that the production increase be limited to 162,000 ADMT per year until the installation of the HCE blow heat recovery system.

Carbon monoxide emissions have been estimated using the NCASI Technical Bulletins referenced above. There are no emission factors that separate out chlorine stages from chlorine dioxide stages. The facility uses both. Chlorine stages produce little to no CO. ClO_2 stages produce a maximum depending on the lignin content of the entering pulp and the ClO_2 charged, but only up to a certain point. Technical Bulletin 760 indicates that CO emissions remained fairly constant between 0.59 and 0.73 kg/ODMTUB when increasing ClO_2 substitution. This is equilivent to 1.606 lb/ODMTUP. At 175,000 ADMT finished pulp is equivalent to 218,750 ODMTUP. As a conservative analysis this application used 1.606 lbCO/ODMTUP and determined that CO emissions would increase by 25.12 tons per year. This is less than the PSD Significance Level of 100 tons per year.

3.5.5 Evaporator System Vent

The emissions from this source are based on the required methanol performance tests. They have been increased by 16.70 percent to account for the production increase.

3.5.6 Wastewater Treatment System Emissions

The emissions from the wastewater treatment system have been taken from the annual report. These emissions are determined using WATER9 similar to its use to determine compliance with the Subpart S MACT rule. They have been increased by 16.70 percent to account for the production increase.

Table 13. Pulping, Bleaching, Evaporation, Wastewater Systems SO_2 and VOC Emissions in TPY from 16.70% Production Increase

Year	VOC		SO_2		CO	
Pulping Systems (VGS)						
2000			79.00		0	
2001			51.84		0	
2002			21.36		0	
2003	26.72		13.34	12.295	0	
2004	46.52		11.25		0	
Baseline	36.62		65.42		NA	
Increase 8%		2.930		10.925		0
Increase 16.70%		6.116		10.925		
Bleaching Systems 2.05						
2003	178.17		0			
2004	177.84		0			
Baseline	178.00		NA			
HCE blow heat recovey	(71.20)					
Increase 8% no heat recovery project		14.24				
Increase 16.70% and recovery project		(41.47)				25.12
Increas 16.70% and no RB project 29.726 **Evaporators**						
2003	50.72		0		0	
2004	56.72		0		0	
Baseline	53.72		NA		NA	
Increase 8%		4.297		0		0
Increase 16.70%		8.971				
Wastewater Treatment System						
2003	76.89		0		0	
2004	55.64		0		0	
Baseline	66.26		NA		NA	
Increase 8%		5.301		0		0
Increase 16.70%		11.065				
Grand Total at 8% increase and no heat recovery project		26.77		10.925		
Grand Total at 16.70% increase and heat recovery project / no RB project		(15.318) / 44.813				25.12
Significance Level		40		40		100

?

44,813 ↑ VOC

From Table 13 it can be determined that the proposed increase in production will not cause an increase in applicable pollutants beyond the Significance Level. Therefore, this PSD analysis of the installation of No. 6 digester along with a production increase from 149,947 ADMT per year to 175,000 ADMT per year will not require a PSD permit.

The production increase is included in the construction permit application.

APPENDIX A

Emissions Source	Fuel Type	Parameter	Source of Annual Operating Report Emissions for 2004	Any variances from the 2004 source in preceding years.
No. 1 PB	Oil	CO	AP 42 emissions factor.	Same source for preceding years.
No. 1 PB	Oil	NOX	AP 42 emissions factor.	Same source for preceding years.
No. 1 PB	Oil	SO2	Calculated from actual oil burned, % sulfur analyses and the scrubber SO2 removal efficiency.	Same source for preceding years.
No. 1 PB	Oil	PM	1999 special testing determined the ratio of PM from No. 1 PB to the total PM measured during the A-scrubber stack test. A-scrubber receives flue gas from No. 1 and No. 2 PB. This ratio and the actual A-scrubber PM emissions are used to calculate the No. 1 PB emissions in pounds/hr. This value is then multiplied by the actual hours operated for No. 1 PB.	Same source for preceding years.
No. 1 PB	Oil	PM10	The AP42 ratio of PM10 to PM is multiplied by the PM emissions.	Same source for preceding years.
No. 1 PB	Oil	VOC	AP42 emissions factor.	Same source for preceding years.
No. 1 PB	Oil	MeOH	Methanol was tested from all three power boilers in 1991 at 0.75 lb/hr. This value is prorated by the fuel type, heat input rate and actual operating hours to each boiler. The source of the methanol is likely the recycled mill process water used in the scrubber.	Same for 2001-2003. No estimates for methanol were made for 2000.
No. 2 PB	Oil	CO	AP 42 emissions factor.	Same source for preceding years.
No. 2 PB	Oil	NOX	AP 42 emissions factor.	Same source for preceding years.
No. 2 PB	Oil	SO2	Calculated from actual oil burned, % sulfur analyses and the scrubber SO2 removal efficiency.	Same source for preceding years.
No. 2 PB	Oil	PM	AP42 emissions factor multiplied by the A-Scrubber PM removal efficiency.	Same source for preceding years.
No. 2 PB	Oil	PM10	AP42 emissions factor multiplied by the A-Scrubber PM removal efficiency.	Same source for preceding years.
No. 2 PB	Oil	VOC	AP42 emissions factor.	Same source for preceding years.

Emissions Source	Fuel Type	Parameter	Source of Annual Operating Report Emissions for 2004	Any variances from the 2004 source in preceding years.
No. 2 PB	Oil	MeOH	Methanol was tested from all three power boilers in 1991 at 0.75 lb/hr. This value is prorated by the fuel type, heat input rate and actual operating hours to each boiler. The source of the methanol is likely the recycled mill process water used in the scrubber.	Same for 2001-2003. No estimates for methanol were made for 2000.
No. 2 PB	Bark	CO	2004 test of A- Scrubber minus the CO from oil burning calculated for No. 1 and No. 2 boilers.	2000 – 2003 by AP42 emissions factor.
No. 2 PB	Bark	NOX	2004 test of A- Scrubber minus the NOX from oil burning calculated for No. 1 and No. 2 boilers.	2000 – 2003 by AP42 emissions factor.
No. 2 PB	Bark	SO2	AP42 emissions factor times the SO2 removal efficiency of the A-Scrubber.	Same source for preceding years.
No. 2 PB	Bark	PM	Actual A-scrubber PM test emissions multiplied by the actual operating hours minus No. 1 and No. 2 PB oil PM emissions.	Same source for preceding years.
No. 2 PB	Bark	PM10	The AP42 ratio of PM10 to PM is multiplied by the PM emissions.	Same source for preceding years.
No. 2 PB	Bark	VOC	AP42 emissions factor.	Same source for preceding years.
No. 2 PB	Bark	MeOH	Methanol was tested from all three power boilers in 1991 at 0.75 lb/hr. This value is prorated by the fuel type, heat input rate and actual operating hours to each boiler. The source of the methanol is likely the recycled mill process water used in the scrubber.	Same for 2001-2003. No estimates for methanol were made for 2000.

Emissions Source	Fuel Type	Parameter	Source of Annual Operating Report Emissions for 2004	Any variances from the 2004 source in preceding years.
No. 3 PB	Oil	CO	AP 42 emissions factor.	Same source for preceding years.
No. 3 PB	Oil	NOX	AP 42 emissions factor.	Same source for preceding years.
No. 3 PB	Oil	SO2	Calculated from actual oil burned, % sulfur analyses and the scrubber SO2 removal efficiency.	Same source for preceding years.
No. 3 PB	Oil	PM	AP42 emissions factor multiplied by the B-scrubber PM removal efficiency.	Same source for preceding years.
No. 3 PB	Oil	PM10	AP42 emissions factor multiplied by the B-scrubber PM removal efficiency.	Same source for preceding years.
No. 3 PB	Oil	VOC	AP42 emissions factor.	Same source for preceding years.
No. 3 PB	Oil	MeOH	Methanol was tested from all three power boilers in 1991 at 0.75 lb/hr. This value is prorated by the fuel type, heat input rate and actual operating hours to each boiler. The source of the methanol is likely the recycled mill process water used in the scrubber.	Same for 2001-2003. No estimates for methanol were made for 2000.
No. 3 PB	Bark	CO	2004 test of B- Scrubber minus the CO from oil burning calculated for No. 3 boiler.	2000 – 2003 by AP42 emissions factor.
No. 3 PB	Bark	NOX	2004 test of B- Scrubber minus the NOX from oil burning calculated for No. 3 boiler.	2000 – 2003 by AP42 emissions factor.
No. 3 PB	Bark	SO2	AP42 emissions factor times the SO2 removal efficiency of the A-Scrubber.	Same source for preceding years.
No. 3 PB	Bark	PM	Actual B-scrubber PM test emissions multiplied by the actual operating hours minus No. 3 oil PM emissions.	Same source for preceding years.
No. 3 PB	Bark	PM10	The AP42 ratio of PM10 to PM is multiplied by the PM emissions.	Same source for preceding years.
No. 3 PB	Bark	VOC	AP42 emissions factor.	Same source for preceding years.

Emissions Source	Fuel Type	Parameter	Source of Annual Operating Report Emissions for 2004	Any variances from the 2004 source in preceding years.
No. 3 PB	Bark	MeOH	Methanol was tested from all three power boilers in 1991 at 0.75 lb/hr. This value is prorated by the fuel type, heat input rate and actual operating hours to each boiler. The source of the methanol is likely the recycled mill process water used in the scrubber.	Same for 2001-2003. No estimates for methanol were made for 2000.
Rec. Boil.	Oil	CO	AP42 emissions factor.	Same source for preceding years.
Rec. Boil.	Oil	NOX	AP42 emissions factor.	Same source for preceding years.
Rec. Boil.	Oil	SO2	Calculated from actual oil burned, % sulfur analyses and the scrubber SO2 removal efficiency.	Same source for preceding years.
Rec. Boil.	Oil	PM	AP42 emissions factor multiplied by the recovery scrubber PM removal efficiency.	Same source for preceding years.
Rec. Boil.	Oil	PM10	AP42 emissions factor multiplied by the recovery scrubber PM removal efficiency.	Same source for preceding years.
Rec. Boil.	Oil	VOC	AP42 emissions factor.	Same source for preceding years.
Rec. Boil.	Oil	MeOH	Assumed to be zero from oil burning.	
Rec. Boil.	SSLS	CO	Actual ppmV CO readings from the boiler's CO CMS & annual stack test flue gas volume flow rate are used to calculate the tons CO/yr. Then the oil burning CO is subtracted from this value.	2003 same as 2004. 2000-2002 used 1995 tests for CO ppmV.
Rec. Boil.	SSLS	NOX	2004 testing ppmV NOX readings and annual stack test flue gas volume flow rate are used to calculate the tons NOX/yr. Then the oil burning NOX is subtracted from this value.	2000-2003: 1995 test data used for NOX ppmV.
Rec. Boil.	SSLS	SO2	Actual ppmV SO2 reading from the boiler's SO2 CEM & annual stack test flue gas volume flow rate are used to calculate the tons SO2/yr. Then the oil burning SO2 is subtracted from this value.	Same source for preceding years.

Emissions Source	Fuel Type	Parameter	Source of Annual Operating Report Emissions for 2004	Any variances from the 2004 source in preceding years.
Rec. Boil.	SSLS	PM	Annual stack test PM lb/hr and actual operating hours are used along with a ratio of the annual average liquor burning rate to the stack test liquor burning rate.	Same 2002 & 2003. For 2000-2001 the stack test liquor burning rate was used; no compensation for annual average burn rate.
Rec. Boil.	SSLS	PM10	Utilized bark burning AP42 ration of PM10 to PM and the actual PM emissions.	Same source for preceding years.
Rec. Boil.	SSLS	VOC	Measured methanol emissions divided by a literature based ration of methanol to VOC for spent sulfite liquor evaporators of 0.95.	2003 same as 2004. 2000-2002 by AP42 emissions factor.
Rec. Boil.	SSLS	MeOH	Annual methanol emissions test in lb/ODUBT pulp multiplied by actual ODUBT/yr. These emissions are actually from the evaporator methanol condenser discharge, which is piped to the recovery boiler scrubber.	Same for 2002 & 2003. 2000-2001 based on an average of 1991- report year testing for lb MeOH/ODUBT.
Pulping	Pulp Prod.	SO2	Actual ppmV SO2 reading from the vent gas scrubber SO2 CEM & flue gas volume flow rate from previous testing [from constant flow fan] are used to calculate the tons SO2/yr.	Same source for preceding years.
Pulping	Pulp Prod.	MeOH	Annual methanol emissions test in lb/ODUBT pulp multiplied by actual ODUBT/yr.	Same for 2002 & 2003. 2000-2001 based on an average of 1991- report year testing for lb MeOH/ODUBT.
Pulping	Pulp Prod.	VOC	Sum of all HAPs for which there are test data or emissions factors and are included as VOC under FAC 62.24.200 using actual pulp production or liquor burned values.	Same 2001 – 2003. For 2000, VOC assumed to equal methanol divided by a literature MeOH/VOC ratio.
Bleaching	Pulp Prod.	VOC	VOC is assumed to be equal to methanol in the bleach plant.	Same for 2003. No bleaching VOC estimate for 2000-2002.

Emissions Source	Fuel Type	Parameter	Source of Annual Operating Report Emissions for 2004	Any variances from the 2004 source in preceding years.
Bleaching	Pulp Prod.	MeOH	2000 special testing in the bleach plant resulted in a lb MeOH/ODUBT value which is multiplied by the actual annual tonnage.	Same 2001 - 2003.
Evaporators	Pulp Prod.	VOC	VOC is assumed to be equal to methanol emissions.	Same for 2003. No evaporators VOC estimate for 1999-2002.
Evaporators	Pulp Prod.	MeOH	1999 test data summary provided a lbMeOH/ODUBT value for the evaporator area. This value is multiplied by the actual pulp production for the year.	Same 2001 – 2003.
Waste Water	Pulp Prod.	VOC	Sum of all HAPs for which there are test data or emissions factors for waste water and are included as VOC under FAC 62.24.200 using actual pulp production or waste water flow values.	Same for 2003. No wastewater VOC estimates for 1999-2002.
Waste Water	Pulp Prod.	MeOH	Methanol is based on the annual water 9 model results, which accompanies the annual stack testing for methanol. The model calculation provides a lb MeOH/ODUBT for the waste water treatment system. This value is multiplied by the actual pulp production for the year.	Same 2002 & 2003. 2001 used the water 8 model.