Report

AIR CONSTRUCTION PERMIT APPLICATIONS FOR MODIFICATION TO THE NO. 6 RECOVERY BOILER

RAYONIER PERFORMANCE FIBERS, LLC
NASSAU COUNTY, FLORIDA

RECEIVED
OCT 20 2009
BUREAU OF AIR REGULATION

Submitted To: Rayonier Performance Fibers, LLC
P.O. Box 2002
Fernandina Beach, FL 32035

Submitted By: Golder Associates Inc.
6026 NW 1st Place
Gainesville, FL 32607 USA

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OCT 15 2009
NORTHEAST DISTRICT
DEP - JACKSONVILLE

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0938-7544

Golder Associates

APPLICATION FOR AIR PERMIT – LONG FORM

Department of Environmental Protection

Division of Air Resource Management

APPLICATION FOR AIR PERMIT - LONG FORM

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NORTHEAST DISTRICT
DEP - JACKSONVILLE

I. APPLICATION INFORMATION

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

- For any required purpose at a facility operating under a federally enforceable state air operation permit (FESOP) or Title V air operation permit;
- For a proposed project subject to prevention of significant deterioration (PSD) review, nonattainment new source review, or maximum achievable control technology (MACT);
- To assume a restriction on the potential emissions of one or more pollutants to escape a requirement such as PSD review, nonattainment new source review, MACT, or Title V; or
- To establish, revise, or renew a plantwide applicability limit (PAL).

Air Operation Permit – Use this form to apply for:

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

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 Rogers, Manager, Environmental Operations**
2. Application Contact Mailing Address... Organization/Firm: **Rayonier Performance Fibers, LLC** Street Address: **Post Office Box 2002** City: **Fernandina Beach** State: **FL** Zip Code: **32035**
3. Application Contact Telephone Numbers... Telephone: **(904) 277-1346** ext. Fax: **(904) 261-0333**
4. Application Contact E-mail Address: **david.rogers@rayonier.com**

Application Processing Information (DEP Use)

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

APPLICATION INFORMATION

Purpose of Application

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

Air Construction Permit

☒ Air construction permit.

☐ Air construction permit to establish, revise, or renew a plantwide applicability limit (PAL).

☐ Air construction permit to establish, revise, or renew a plantwide applicability limit (PAL), and separate air construction permit to authorize construction or modification of one or more emissions units covered by the PAL.

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

Air Construction Permit application to replace the steam drum, mud drum, and air heater components on the Recovery Boiler (EU 006). As a result of this work, the generating bank steam tubes will also have to be replaced.

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Processing Fee
006	Recovery Boiler	AC1B	N/A

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, General Manager**
2.	Owner/Authorized Representative Mailing Address... Organization/Firm: **Rayonier Performance Fibers, LLC** Street Address: **P.O. 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 E-mail Address: **jack.perrett@rayonier.com**
5.	Owner/Authorized Representative Statement: *I, the undersigned, am the owner or authorized representative of the corporation, partnership, or other legal entity submitting this air permit application. To the best of my knowledge, the statements made in this application are true, accurate and complete, and any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department.* [signature] 13OCT09 Signature Date

APPLICATION INFORMATION

Application Responsible Official Certification

Complete if applying for an initial, revised, or renewal Title V air operation permit or concurrent processing of an air construction permit and revised or renewal Title V air operation 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, CAIR source, or Hg Budget 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 E-mail 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: **6026 NW 1st Place** City: **Gainesville** State: **FL** Zip Code: **32607**
3.	Professional Engineer Telephone Numbers... Telephone: **(352) 336-5600** ext. **21145** Fax: **(352) 336-6603**
4.	Professional Engineer E-mail 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 ☒, 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 10/12/09 Signature Date (seal)

* Attach any exception to certification statement.
**Board of Professional Engineers Certificate of Authorization #00001670.

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) **30 / 39 / 44** Longitude (DD/MM/SS) **81 / 29 / 03**	
3. Governmental Facility Code: **N/A**	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: **David Rogers, Manager, Environmental Operations**
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) 277-1346** ext. Fax: **(904) 261-0333**
4. Facility Contact E-mail Address: **david.rogers@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 E-mail Address:

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:	

List of Pollutants Emitted by Facility

1. Pollutant Emitted	2. Pollutant Classification	3. Emissions Cap [Y or N]?
Particulate Matter Total – PM	**A**	**N**
Particulate Matter less than 10 microns – PM10	**A**	**N**
Particulate Matter less than 2.5 microns – PM2.5	**A**	**N**
Sulfur Dioxide – SO2	**A**	**N**
Nitrogen Oxides – NOx	**A**	**N**
Carbon Monoxide – CO	**A**	**N**
Volatile Organic Compounds – VOC	**A**	**N**
Lead – Pb	**B**	**N**
Total Reduced Sulfur – TRS	**B**	**N**
Hydrogen Sulfide – H2S	**B**	**N**
Total Hazardous Air Pollutants – HAPS	**A**	**N**
H001 – Acetaldehyde	**A**	**N**
H006 – Acrolein	**B**	**N**
H017 – Benzene	**B**	**N**
H032 – Carbon Disulfide	**B**	**N**
H033 – Carbon Tetrachloride	**B**	**N**
H038 – Chlorine	**A**	**N**
H041 – Chlorobenzene	**B**	**N**
H043 – Chloroform	**A**	**N**
H047 – Cobalt	**B**	**N**
H061 – 1,4-Dichlorobenzene	**B**	**N**
H085 – Ethyl Benzene	**B**	**N**
H095 – Formaldehyde	**B**	**N**
H104 – Hexane	**B**	**N**
H106 – Hydrochloric Acid	**B**	**N**
H113 – Manganese	**B**	**N**
H114 – Mercury	**B**	**N**
H115 – Methanol	**A**	**N**
H117 – Bromomethane	**B**	**N**
H118 – Chloromethane	**B**	**N**
H119 – 1,1,1-Trichloroethane	**B**	**N**
H123 – Methyl Isobutyl Ketone	**B**	**N**
H128 – Methylene Chloride	**B**	**N**
H133 – Nickel	**B**	**N**
H148 – Phosphorus	**B**	**N**
H163 – Styrene	**B**	**N**
H165 – 2,3,7,8-Tetrachlorodibenzo-p-dioxin	**B**	**N**
H166 – 1,1,2,2-Tetrachloroethane	**B**	**N**
H167 – Tetrachloroethane	**B**	**N**
H169 – Toluene	**B**	**N**
H174 – 1,2,4-Trichlorobenzene	**B**	**N**
H176 - Trichloroethylene	**B**	**N**
H187 - Xylene	**B**	**N**

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'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:

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) ☐ Attached, Document ID:______ ☒ Previously Submitted, Date: Dec 2007
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) ☐ Attached, Document ID:______ ☒ Previously Submitted, Date: Dec 2007
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: RPF-FI-C3 ☐ Previously Submitted, Date:________

Additional Requirements for Air Construction Permit Applications

1.	Area Map Showing Facility Location: ☐ Attached, Document ID:__________ ☒ Not Applicable (existing permitted facility)
2.	Description of Proposed Construction, Modification, or Plantwide Applicability Limit (PAL): ☒ Attached, Document ID: Attachment A
3.	Rule Applicability Analysis: ☒ Attached, Document ID: Attachment A
4.	List of Exempt Emissions Units: ☐ Attached, Document ID:__________ ☒ Not Applicable (no exempt units at facility)
5.	Fugitive Emissions Identification: ☐ Attached, Document ID:__________ ☒ Not Applicable
6.	Air Quality Analysis (Rule 62-212.400(7), F.A.C.): ☐ Attached, Document ID:__________ ☒ Not Applicable
7.	Source Impact Analysis (Rule 62-212.400(5), F.A.C.): ☐ Attached, Document ID:__________ ☒ Not Applicable
8.	Air Quality Impact since 1977 (Rule 62-212.400(4)(e), F.A.C.): ☐ Attached, Document ID:__________ ☒ Not Applicable
9.	Additional Impact Analyses (Rules 62-212.400(8) and 62-212.500(4)(e), F.A.C.): ☐ Attached, Document ID:__________ ☒ Not Applicable
10.	Alternative Analysis Requirement (Rule 62-212.500(4)(g), F.A.C.): ☐ Attached, Document ID:__________ ☒ Not Applicable

C. FACILITY ADDITIONAL INFORMATION (CONTINUED)

Additional Requirements for FESOP Applications

1. List of Exempt Emissions Units:
   ☐ 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 Onsite 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

C. FACILITY ADDITIONAL INFORMATION (CONTINUED)

Additional Requirements for Facilities Subject to Acid Rain, CAIR, or Hg Budget Program

1.	Acid Rain Program Forms: Acid Rain Part Application (DEP Form No. 62-210.900(1)(a)): ☐ Attached, Document ID:__________ ☐ Previously Submitted, Date:__________ ☒ Not Applicable (not an Acid Rain source) Phase II NO_X Averaging Plan (DEP Form No. 62-210.900(1)(a)1.): ☐ Attached, Document ID:__________ ☐ Previously Submitted, Date:__________ ☒ Not Applicable New Unit Exemption (DEP Form No. 62-210.900(1)(a)2.): ☐ Attached, Document ID:__________ ☐ Previously Submitted, Date:__________ ☒ Not Applicable
2.	CAIR Part (DEP Form No. 62-210.900(1)(b)): ☐ Attached, Document ID:__________ ☐ Previously Submitted, Date:__________ ☒ Not Applicable (not a CAIR source)
3.	Hg Budget Part (DEP Form No. 62-210.900(1)(c)): ☐ Attached, Document ID:__________ ☐ Previously Submitted, Date:__________ ☒ Not Applicable (not a Hg Budget unit)

Additional Requirements Comment

ATTACHMENT RPF-FI-C3

PRECAUTIONS TO PREVENT EMISSIONS OF UNCONFINED PARTICULATE MATTER

ATTACHMENT RPF – FI – C3

PRECAUTIONS TO PREVENT EMISSIONS OF UNCONFINED PARTICULATE MATTER

Fernandina Beach Mill takes reasonable precautions to prevent emissions of unconfined particulate matter that include the following requirements.

Emissions Point Vent Number	Emissions Point Name	Description and Control Measures
WY001	Chip pit blower	Fresh chips are pneumatically conveyed to a chip pile by a blower. Chipping technology minimizes the production of fines. Also, chips are made from freshly cut pine trees having a moisture content of about 50 percent. This moisture aids in keeping any dust that might be made airborne.
WY004	Chip pile	Chipping technology minimizes the production of fines. Chips are made from freshly cut pine trees having a moisture content of about 50 percent. This moisture aids in keeping any dust that might be made airborne. Also, frequent rains keep the chip pile sufficiently wet to control windborne particulate.
WY006	Bark pile	Bark has at least 50 percent moisture and is created in large pieces. Some of the bark must be hogged before burning. Therefore, little becomes airborne from the pile. Furthermore, frequent rains maintain the pile at sufficient moisture to suppress dusting.
AP003	Molten sulfur handling area	Fugitive emissions from the molten sulfur handing areas are regulated by Rule 62-296.411, F.A.C. These rules require curbing and drip pans at unloading areas. Cleanup of spills must occur periodically. Logs must be kept on spills. All of these actions are implemented. They provide the means of minimizing the release of unconfined particulate matter from this source.

III. EMISSIONS UNIT INFORMATION

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 an initial, revised or renewal 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. 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 an 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 or 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. A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit addressed in this application that is subject to air construction permitting and for each such emissions unit that is a regulated or unregulated unit for purposes of Title V permitting. (An emissions unit may be exempt from air construction permitting but still be classified as an unregulated unit for Title V purposes.) Emissions units classified as insignificant for Title V purposes 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.

EMISSIONS UNIT INFORMATION
Section [1]
Recovery Boiler

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.)

   ☐ 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).

   ☐ 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:

   Recovery Boiler

3. Emissions Unit Identification Number: **006**

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:
A			**26**

8. Federal Program Applicability: (Check all that apply)

   ☐ Acid Rain Unit

   ☐ CAIR Unit

   ☐ Hg Budget Unit

9. Package Unit:
   Manufacturer: Model Number:

10. Generator Nameplate Rating: MW

11. Emissions Unit Comment:

    Sulfite recovery boiler controlled by a wet scrubber and demister.

Emissions Unit Control Equipment/Method: Control 1 of 2

1. Control Equipment/Method Description: **Mist Eliminator – High Velocity (V > 250 ft/min): Brinks type mist eliminator for particulates**	
2. Control Device or Method Code: **014**	

Emissions Unit Control Equipment/Method: Control 2 of 2

1. Control Equipment/Method Description: **Tray-Type Gas Adsorption Column: Liquid scrubber that controls combustion gases from the boiler and non-condensable gases from the evaporators.**	
2. Control Device or Method Code: **051**	

Emissions Unit Control Equipment/Method: Control ____ of ____

1. Control Equipment/Method Description:	
2. Control Device or Method Code:	

Emissions Unit Control Equipment/Method: Control ____ of ____

1. Control Equipment/Method Description:	
2. Control Device or Method Code:	

B. EMISSIONS UNIT CAPACITY INFORMATION
(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate: **70,000 lb/hr oven dry Red Liquor Solids**	
2. Maximum Production Rate:	
3. Maximum Heat Input Rate: **653.1** million Btu/hr	
4. Maximum Incineration Rate: pounds/hr tons/day	
5. Requested Maximum Operating Schedule: **24** hours/day **52** weeks/year	 **7** days/week **8,760** 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: **RB**	2. Emission Point Type Code: **2**	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: **EU 021 - Methanol Condenser**		
5. Discharge Type Code: **V**	6. Stack Height: **264** feet	7. Exit Diameter: **7.33** Feet
8. Exit Temperature: **126**°F	9. Actual Volumetric Flow Rate: **160,096** acfm	10. Water Vapor: **13.55** %
11. Maximum Dry Standard Flow Rate: **125,280*** dscfm	12. Nonstack Emission Point Height: Feet	
13. Emission Point UTM Coordinates... Zone: **17** East (km): **454.7** North (km): **3392.2**	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)	
15. Emission Point Comment: ***Maximum dry standard flow rate is at 8-percent O_2.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 3

1. Segment Description (Process/Fuel Type): **Industrial Processes; Sulfite Pulping; Recovery System: NH3; Red Liquor Solids.**		
2. Source Classification Code (SCC): **3-07-002-22**	3. SCC Units: **Tons Air-Dried Unbleached Pulp (ADUP)**	
4. Maximum Hourly Rate: **35.51**	5. Maximum Annual Rate: **311,068**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **20**
10. Segment Comment: **Hourly: (70,000 lb SSLS/hr) x (34.7 tons ADUP/cook) x (1 cook/68,400 lb SSLS) = 35.51 tons ADUP/hr** **Annual: (35.51 tons/hr ADUP) x (8,760 hr/yr) = 311,068 tons ADUP/yr.**		

Segment Description and Rate: Segment 2 of 3

1. Segment Description (Process/Fuel Type): **External Combustion Boilers; Industrial; Residual Oil; Grade 6 Oil.**		
2. Source Classification Code (SCC): **1-02-004-01**	3. SCC Units: **Thousand Gallons Burned**	
4. Maximum Hourly Rate: **1.789**	5. Maximum Annual Rate: **15,671.6**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **2.5**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **150**
10. Segment Comment: **This segment includes 150 bbl/yr of facility generated on spec used oil distributed among the No. 6 Power Boiler and the Recovery Boiler.**		

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

Segment Description and Rate: Segment 3 of 3

1. Segment Description (Process/Fuel Type): **External Combustion Boilers; Industrial; Distillate Oil; Grades 1 and 2 Oil.**		
2. Source Classification Code (SCC): **1-02-005-01**	3. SCC Units: **Thousand Gallons Burned**	
4. Maximum Hourly Rate: **0.030**	5. Maximum Annual Rate: **262.8**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.0015**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **136**
10. Segment Comment: **Permitted ultra low sulfur diesel fuel usage from permit No. 0890004-024-AC. Annual usage based on 8,760 hr/yr at 30 gal/hr.**		

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
PM	051	014	EL
PM10	051	014	NS
PM2.5	051	014	NS
SO2	051	014	EL
NOx			NS
CO			NS
VOC			NS
SAM	051	014	NS
HAPS (Total)			NS
Acetaldehyde – H001			NS
Manganese – H113			NS
Methanol – H115			NS
Trichlorobenzene – H124			NS
Nickel – H133			NS
Phosphorus – H148			NS
m,p-Xylene – H186			NS
o-Xylene – H187			NS

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 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 operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **SO2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **321.9** lb/hour **1,409.92** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **321.9 lb/hr and 1,409.92 TPY** Reference: **Permit No. 0890004-017-AC**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): **1,008.8** tons/year	8.b. Baseline 24-month Period: From: **January 1999** To: **December 2000**
9.a. Projected Actual Emissions (if required): **836.75** tons/year	9.b. Projected Monitoring Period: ☒ 5 years ☐ 10 years
10. Calculation of Emissions: **Hourly: 321.9 lb/hr (Permit Limit)** **Annual: 1,409.92 TPY (Permit Limit)**	
11. Potential, Fugitive, and Actual Emissions Comment: **SO_2 limited to 300 ppmvd (3-hour average).**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 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: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **300 ppmvd (3-hr average)**	4. Equivalent Allowable Emissions: **321.9** lb/hour **1,409.92** tons/year
5. Method of Compliance: **Continuous Emissions Monitoring System (CEMS)**	
6. Allowable Emissions Comment (Description of Operating Method): **Permit No. 0890004-017-AC**	

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, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 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 operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **42.95** lb/hour **188.13** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.040 gr/dscf @ 8% O_2** Reference: **Permit No. 0890004-017-AC**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): **91.19** tons/year	8.b. Baseline 24-month Period: From: **January 2005** To: **December 2006**
9.a. Projected Actual Emissions (if required): **96.24** tons/year	9.b. Projected Monitoring Period: ☒ 5 years ☐ 10 years

10. Calculation of Emissions:

Hourly: 125,280 dscf/min x 0.040 gr/dscf x 60 min/hr x 1 lb/7,000 gr = 42.95 lb/hr

Annual: 42.95 lb/hr x 8,760 hr/yr x 1 ton/2,000 lb = 188.13 TPY

11. Potential, Fugitive, and Actual Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 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: **0.040 gr/dscf @ 8% O2**	4. Equivalent Allowable Emissions: **42.95** lb/hour **188.13** tons/year
5. Method of Compliance: **Annual stack test using EPA Method 5**	
6. Allowable Emissions Comment (Description of Operating Method): **40 CFR 63.862(a)(2) and Permit No. 0890004-017-AC**	

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, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 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 operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **PM10**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **38.96** lb/hour **170.6** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **90.7-percent of PM** Reference: **NCASI Technical Bulletin No. 884**	7. Emissions Method Code: **5**
8.a. Baseline Actual Emissions (if required): **82.85** tons/year	8.b. Baseline 24-month Period: From: **January 2005** To: **December 2006**
9.a. Projected Actual Emissions (if required): **87.51** tons/year	9.b. Projected Monitoring Period: ☒ 5 years ☐ 10 years
10. Calculation of Emissions: **Hourly: 42.95 lb/hr PM x 90.7% = 38.96 lb/hr** **Annual: 188.13 TPY PM x 90.7% = 170.63 TPY**	
11. Potential, Fugitive, and Actual Emissions Comment: **Maximum emissions representative of RLS firing.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 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):	

<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, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 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 operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **PM2.5**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **31.65** lb/hour **138.7** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **73.7-percent of PM** Reference: **NCASI Technical Bulletin No. 884**	7. Emissions Method Code: **5**
8.a. Baseline Actual Emissions (if required): **67.57** tons/year	8.b. Baseline 24-month Period: From: **January 2005** To: **December 2006**
9.a. Projected Actual Emissions (if required): **71.47** tons/year	9.b. Projected Monitoring Period: ☒ 5 years ☐ 10 years
10. Calculation of Emissions: **Hourly: 42.95 lb/hr PM x 73.7% = 31.65 lb/hr** **Annual: 188.13 TPY PM x 73.7% = 138.65 TPY**	
11. Potential, Fugitive, and Actual Emissions Comment: **Maximum emissions representative of RLS firing.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 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):	

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, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 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 operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **NOx**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **548.45** lb/hour **2,402.2** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **15.67 lb/ton RLS** Reference: **Stack Test Average**	7. Emissions Method Code: **1**
8.a. Baseline Actual Emissions (if required): **1,977.46** tons/year	8.b. Baseline 24-month Period: From: **January 2004** To: **December 2005**
9.a. Projected Actual Emissions (if required): **2,013.56** tons/year	9.b. Projected Monitoring Period: ☒ 5 years ☐ 10 years
10. Calculation of Emissions: **Hourly: 15.67 lb/ton RLS x 35 TPH RLS = 548.45 lb/hr** **Annual: 548.45 lb/hr x 8,760 hr/yr x 1 ton/2,000 lb = 2,402.2 TPY**	
11. Potential, Fugitive, and Actual Emissions Comment: **Maximum emissions representative of RLS firing.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 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):	

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, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 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 operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **533.0** lb/hour **1,352.1** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **See Comment** Reference: **Process monitor data**	7. Emissions Method Code: **1**
8.a. Baseline Actual Emissions (if required): **679.97** tons/year	8.b. Baseline 24-month Period: From: **January 2007** To: **December 2008**
9.a. Projected Actual Emissions (if required): **772.24** tons/year	9.b. Projected Monitoring Period: ☒ 5 years ☐ 10 years

10. Calculation of Emissions:

Hourly: (1,000 ppmvd/10^6) x 2,116.8 lb_f/ft^2 x 60 min/hr x 135,632 dscfm x 28.01 lb/lb-mol x 1/1,545.6 ft-lb_f/lb_m-°R x 1/586 °R = 533.0 lb/hr

Annual: 8.82 lb/ton RLS x 35 TPH RLS x 8,760 hr/yr x 1 ton/2,000 lbs = 1,352.1 TPY

11. Potential, Fugitive, and Actual Emissions Comment:

Maximum emissions representative of RLS firing. Potential hourly emissions based on maximum CO concentration of 1,000 ppmvd. Potential annual emissions based on maximum annual average emission rate of 8.82 lb/ton RLS. Flow rate based on 2008 stack test average @ 6.7% O_2.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 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):	

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, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 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 operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **2.38** lb/hour **10.4** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **20.6% of methanol** Reference: **Stack test data and NCASI Technical Bulletin No. 858**	7. Emissions Method Code: **5**
8.a. Baseline Actual Emissions (if required): **8.45** tons/year	8.b. Baseline 24-month Period: From: **January 2004** To: **December 2005**
9.a. Projected Actual Emissions (if required): **8.81** tons/year	9.b. Projected Monitoring Period: ☒ 5 years ☐ 10 years
10. Calculation of Emissions: **Hourly: 0.33 lb MeOH/ton RLS x 35 TPH RLS x 20.6-percent VOC = 2.38 lb/hr** **Annual: 2.38 lb/hr x 8,760 hr/yr x 1 ton/2,000 lbs = 10.42 TPY**	
11. Potential, Fugitive, and Actual Emissions Comment: **Maximum emissions representative of RLS firing. VOC emission rate based on 20.6 percent of MeOH emissions from NCASI Technical Bulletin No. 858. Refer to Attachment A.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 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):	

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, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 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 operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **SAM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **14.16** lb/hour **62.0** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **4.4-percent of SO2** Reference: **AP-42, Section 1.3**	7. Emissions Method Code: **5**
8.a. Baseline Actual Emissions (if required): **44.39** tons/year	8.b. Baseline 24-month Period: From: **January 1999** To: **December 2000**
9.a. Projected Actual Emissions (if required): **37.21** tons/year	9.b. Projected Monitoring Period: ☒ 5 years ☐ 10 years
10. Calculation of Emissions: **Hourly: 4.4% x 321.9 lb/hr SO2 = 14.16 lb/hr** **Annual: 4.4% x 1,409.9 TPY SO2 = 62.0 TPY**	
11. Potential, Fugitive, and Actual Emissions Comment: **Maximum emissions representative of RLS firing.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 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):	

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, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 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 operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **Pb**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **4.67x10^{-3}** lb/hour **0.020** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **9.6x10^{-5} lb/ton RLS** Reference: **NCASI Technical Bulletin No. 858**	7. Emissions Method Code: **5**
8.a. Baseline Actual Emissions (if required): **1.37x10^{-2}** tons/year	8.b. Baseline 24-month Period: From: **January 2000** To: **December 2001**
9.a. Projected Actual Emissions (if required): **1.35x10^{-2}** tons/year	9.b. Projected Monitoring Period: ☒ 5 years ☐ 10 years

10. Calculation of Emissions:

Hourly:

No. 6 Fuel Oil:

1.789x10^3 gal/hr x 150 MMBtu/10^3 gal = 268.35 MMBtu/hr

1.51x10^{-3} lb/10^3 gal x 1.789x10^3 gal/hr = 2.7x10^{-3} lb/hr

RLS:

653.1 – 268.4 MMBtu/hr = 384.7 MMBtu/hr

384.7 MMBtu/hr x 1 ton/18.66 MMBtu x 9.6x10^{-5} lb/ton = 1.97x10^{-3} lb/hr

Total: 2.7x10^{-3} + 1.97x10^{-3} lb/hr = 4.67x10^{-3} lb/hr

Annual:

No. 6 Fuel Oil:

15,671.6 x10^3 gal/yr x 150 MMBtu/ 10^3 gal = 2,350,740 MMBtu/yr

1.51x10^{-3} lb/10^3 gal x 15,671.6 x10^3 gal/yr x 1 ton/2,000 lbs = 0.0118 TPY

RLS

(653.1 MMBtu/hr x 8,760 hr/yr) - 2,350,740 MMBtu/yr = 3,370,416 MMBtu/yr

3,370,416 MMBtu/yr x 1 ton/18.66 MMBtu x 9.6x10^{-5} lb/ton x 1 ton/2,000 lbs = 0.0087 TPY

Total:

0.0118 TPY + 0.0087 TPY = 0.020 TPY

11. Potential, Fugitive, and Actual Emissions Comment:

Emission rate corresponds to the worst case fuel firing scenario.

No. 6 fuel oil emission factor from AP-42, Table 1.3-11.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 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):	

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, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 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 operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **Mercury - H114**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **$2.99x10^{-4}$** lb/hour **$1.31x10^{-3}$** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **$4.70x10^{-6}$ lb/ton RLS** Reference: **NCASI Technical Bulletin No. 858**	7. Emissions Method Code: **5**
8.a. Baseline Actual Emissions (if required): **$7.38x10^{-4}$** tons/year	8.b. Baseline 24-month Period: From: **January 2000** To: **December 2001**
9.a. Projected Actual Emissions (if required): **$6.95x10^{-4}$** tons/year	9.b. Projected Monitoring Period: ☒ 5 years ☐ 10 years

10. Calculation of Emissions:

Hourly:

No. 6 Fuel Oil:

$1.789x10^3$ gal/hr x 150 MMBtu/10^3 gal = 268.35 MMBtu/hr

$1.13x10^{-4}$ lb/10^3 gal x $1.789x10^3$ gal/hr = $2.02x10^{-4}$ lb/hr

RLS:

653.1 – 268.4 MMBtu/hr = 384.7 MMBtu/hr

384.7 MMBtu/hr x 1 ton/18.66 MMBtu x $4.7x10^{-6}$ lb/ton = $9.69x10^{-5}$ lb/hr

Total: $9.69x10^{-5}$ lb/hr + $2.02x10^{-4}$ lb/hr = $2.99x10^{-4}$ lb/hr

Annual:

No. 6 Fuel Oil:

$15,671.6x10^3$ gal/yr x 150 MMBtu/10^3 gal = 2,350,740 MMBtu/yr

$1.13x10^{-4}$ lb/10^3 gal x $15,671.6x10^3$ gal/yr x 1 ton/2,000 lbs = $8.85x10^{-4}$ TPY

RLS:

(653.1 MMBtu/hr x 8,760 hr/yr) - 2,350,740 MMBtu/yr = 3,370,416 MMBtu/yr

3,370,416 MMBtu/yr x 1 ton/18.66 MMBtu x $4.7x10^{-6}$ lb/ton x 1 ton/2,000 lbs = $4.24x10^{-4}$ TPY

Total:

$8.85x10^{-4}$ TPY + $4.24x10^{-4}$ TPY = $1.31x10^{-3}$ TPY

11. Potential, Fugitive, and Actual Emissions Comment:

Maximum emissions representative of RLS firing.

No. 6 fuel oil emission factor from AP-42, Table 1.3-11.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 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):	

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, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 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 operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **FL**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.067** lb/hour **0.29** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.0373 lb/10³ gal No. 6 Fuel Oil** Reference: **AP-42, Table 1.3-11**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): **0.066** tons/year	8.b. Baseline 24-month Period: From: **January 2000** To: **December 2001**
9.a. Projected Actual Emissions (if required): **0.034** tons/year	9.b. Projected Monitoring Period: ☒ 5 years ☐ 10 years

10. Calculation of Emissions:

Hourly: 0.0373 lb/10^3 gal No. 6 fuel oil x 1.789x10^3 gal/hr = 0.067 lb/hr

Annual: 0.0373 lb/10^3 gal No. 6 fuel oil x 15,671.6x10^3 gal/yr x 1 ton/2,000 lb = 0.29 TPY

11. Potential, Fugitive, and Actual Emissions Comment:
No available data for fluoride emissions due to RLS firing.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 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):	

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 Subsection G 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: **VE20**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **Operation of the Brinks demisters constitutes compliance.**	
5. Visible Emissions Comment: **Permit No. 0890004-017-AC**	

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 [1]
Recovery Boiler

H. CONTINUOUS MONITOR INFORMATION

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

Continuous Monitoring System: Continuous Monitor 1 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **SO2**
3. CMS Requirement:	☐ Rule ☒ Other
4. Monitor Information... Manufacturer: **Siemens** Model Number: **Ultramat SE 7MB1120-1MH20-OBB** Serial Number: **F6-185**	
5. Installation Date: **July 20, 1994**	6. Performance Specification Test Date: **February 24, 2000**
7. Continuous Monitor Comment:	

Continuous Monitoring System: Continuous Monitor 2 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **PM**
3. CMS Requirement:	☐ Rule ☒ Other
4. Monitor Information... Manufacturer: **Mechanical Systems Incorporated (MSI)** Model Number: **Beta Guard PM** Serial Number:	
5. Installation Date: **April 8, 2003**	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Continuous Source Particulate Monitor**	

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)
   ☒ Attached, Document ID: **RPF-EU1-I1** ☐ 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: **RPF-EU1-I2** ☐ 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)
   ☐ Attached, Document ID: ________ ☒ Previously Submitted, Date **2007 (TV Renewal)**

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 **2007 (TV Renewal)**
   ☐ 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)
   ☐ Attached, Document ID: ________ ☐ 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

I. EMISSIONS UNIT ADDITIONAL INFORMATION (CONTINUED)

Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(10) 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 (Rules 62-212.400(4)(d) and 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	

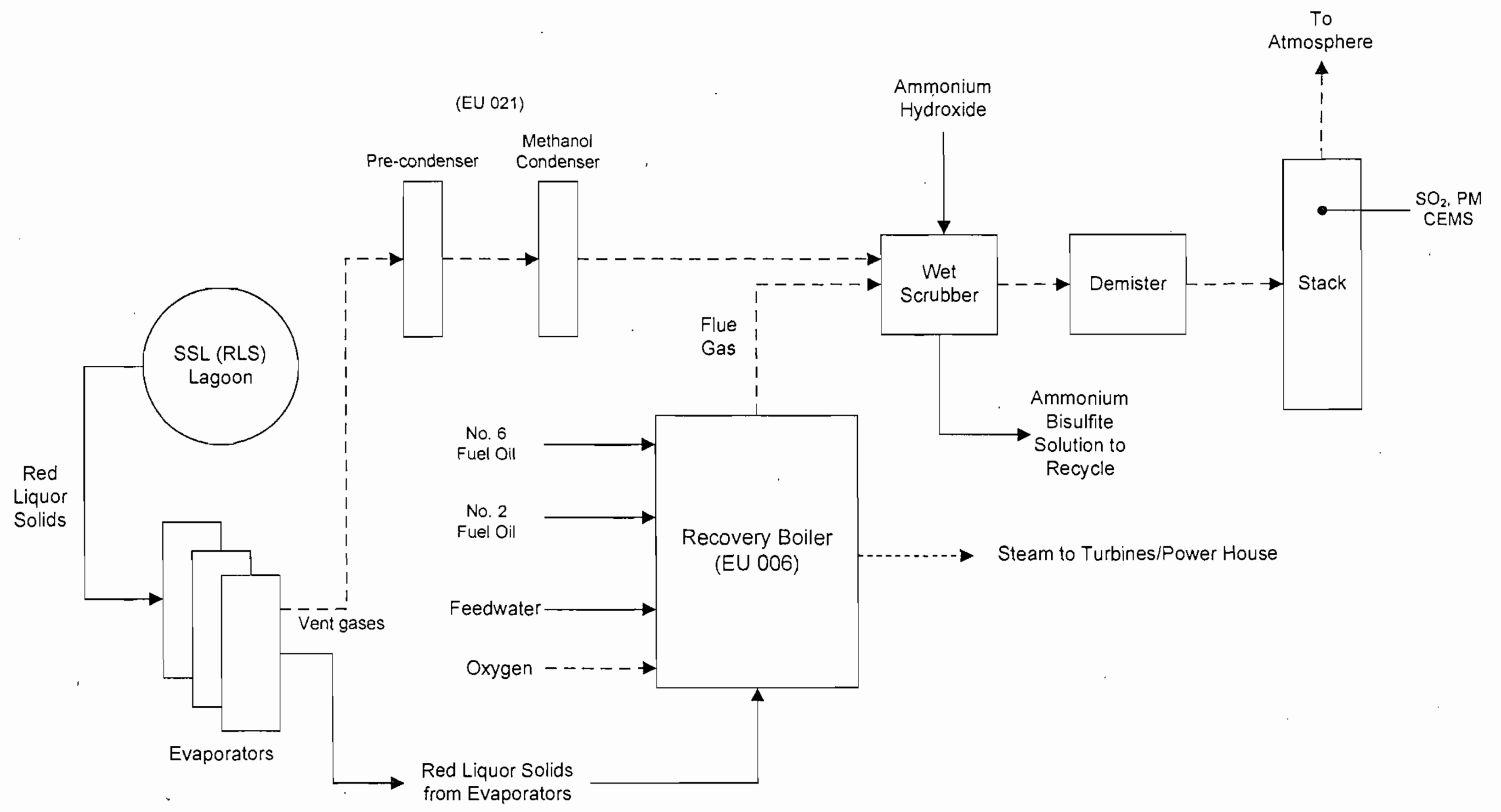
Additional Requirements for Title V Air Operation Permit Applications

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	

Additional Requirements Comment

ATTACHMENT RPF-EU1-I1

PROCESS FLOW DIAGRAM



Attachment RPF-EU1-I1
Recovery Boiler Process Flow Diagram
Rayonier Performance Fibers LLC
Fernandina Beach Mill

Process Flow Legend
Solid/Liquid
Gas
Steam

09387544\RPF-EU1-I1.vsd
Tab: EU1-I1

Golder Associates

ATTACHMENT RPF-EU1-I2

FUEL ANALYSIS

ATTACHMENT RPF-EU1-I2

FUEL ANALYSIS
RECOVERY BOILER

Fuel	Density (lb/gal)	Weight Percent (%) Sulfur	Nitrogen	Ash	Heat Capacity
Red Liquor Solids[a]	--	8.40	3.34	1.56	Avg. 9,330 Btu/lb
No. 2 Fuel Oil[b]	7.13	0.0015	0.006	<0.01	136,000 Btu/gal
No. 6 Fuel Oil	8.21	2.5	--	0.1	145,000 – 150,000 Btu/gal
No. 6 Fuel Oil/ On-spec used oil	8.21	2.5	--	0.1	145,000 – 150,000 Btu/gal

[a] Values provided are in a dry basis.

[b] Source = Perry's Chemical Engineer's Handbook, 7th Edition.

ATTACHMENT A

TABLE OF CONTENTS

LIST OF TABLES

LIST OF APPENDICES

1.0 INTRODUCTION

Rayonier Performance Fibers, LLC (Rayonier) currently operates the Fernandina Beach Mill, located in Nassau County, under Title V operating permit No. 0890004-020-AV. The Rayonier Fernandina Beach Mill is an acid sulfite based pulp mill using ammonia as a base chemical for the manufacture of dissolving pulps.

Rayonier currently operates the Sulfite Recovery Boiler (EU 006) at the mill, among other sources. The boiler is used to produce steam and recover sulfur compounds that are utilized for making the cooking acid used in the digesters. This boiler is permitted to burn red liquor solids (RLS), No. 6 fuel oil, and RLS blended with No. 2 ultra low sulfur diesel (ULSD) fuel. The Recovery Boiler is currently limited to a maximum firing rate of 70,000 pounds per hour (lb/hr) of oven dry RLS (lb/hr RLS), which is equivalent to a maximum heat input rate of 653.1 million British thermal units per hour (MMBtu/hr) based on a RLS heating value of 9,330 Btu per pound (Btu/lb).

Through submission of this air construction permit application, Rayonier is requesting the ability to replace the steam drum, mud drum, and air heater components of the recovery boiler. Additionally, a section of boiler tubes (the generating bank) will have to be removed to allow replacement of the other components, so these tubes must also be replaced. Rayonier may replace these boiler components as soon as December 2009, although current plans are to do this work during the next major outage of the unit, scheduled for February 2010.

Rayonier does not expect an increase in actual emissions as a result of the proposed project, as there will be no increase in process or production rate, and no effect on hourly emissions. Only boiler components will be replaced. Rayonier has performed a comparison of past actual (baseline actual) annual emissions to projected actual annual emissions for the proposed replacement project, based on the new source review (NSR) prevention of significant deterioration (PSD) reform rules. Due to the nature of this comparison, emission increases due to the project are predicted; however, these increases are less than the PSD significant emission rates. Therefore, the project will not trigger NSR under the Federal and State PSD regulations. In reality, there is not expected to be any increase in actual annual emissions due to this project.

A more detailed project description is provided in Section 2.0 of this attachment. PSD review requirements are discussed in Section 3.0 and air emissions estimates and PSD applicability of the project are presented in Section 4.0.

2.0 PROJECT DESCRIPTION

Rayonier is proposing to replace the steam drum, mud drum, and air heater components of the Recovery Boiler. Certain boiler steam tubes will also be replaced. The Recovery Boiler has the emissions unit (EU) number of 006. The Recovery Boiler is currently operating under Title V Operating Permit No. 0890004-020-AV issued May 29, 2007. An air construction permit (No. 0890004-024-AC) was issued for the Recovery Boiler on February 26, 2009, which allowed the ability to fire up to 0.5 gallons per minute (gal/min) of ULSD fuel in combination with RLS.

The Rayonier facility is located at the Foot of Gum Street, Fernandina Beach, Nassau County. The following sections describe the existing Recovery Boiler and the proposed project in more detail.

2.1 Existing Operations

The Recovery Boiler is a spent sulfite liquor (SSL) recovery boiler. The unit fires RLS as the primary fuel to produce steam and recover sulfur compounds used to make the cooking acid for use in the digesters. The RLS contains sulfur compounds, which are converted to sulfur dioxide (SO_2) during combustion. The SO_2 is recovered from the flue gas in a multi-stage wet scrubber that uses ammonium hydroxide as the scrubbing media. The SO_2 reacts with the ammonium hydroxide to form ammonium bisulfite. The ammonium bisulfite solution is drawn off, filtered through sand filters, and pumped to the acid plant to be recycled as the base for making the cooking acid used in the digesters.

The maximum RLS firing rate is 70,000 lb/hr RLS, which is equivalent to a maximum heat input rate of 653.1 MMBtu/hr based on a RLS heating value of 9,330 Btu/lb. This boiler is permitted to burn RLS, No. 6 fuel oil with a maximum sulfur content of 2.5-percent by weight (or a blend of on-spec used oil and No. 6 fuel oil), and RLS blended with No. 2 ULSD fuel. The maximum total addition rate of ULSD fuel to RLS is 0.5 gal/min while firing a maximum of 69,563 lb/hr RLS. The Recovery Boiler is permitted to operate continuously (i.e., 8,760 hours per year).

2.2 Proposed Repairs

Rayonier is proposing to replace the steam drum, mud drum, and air heater components of the Recovery Boiler. The existing components will be replaced with new components of the same function and capacity. Additionally, a section of boiler tubes (the generating bank) will have to be removed to allow replacement of the other components, so these tubes must also be replaced.

Recently, the mud drum experienced cracking and the boiler had to be shut down for repairs. This is an indication that the mud drum needs to be replaced in the near future. When the mud drum is replaced, it is appropriate to also replace the steam drum, air heater, and certain boiler steam tubes.

Rayonier is scheduling an extended outage on the Recovery Boiler in February 2010. Rayonier plans to replace these boiler components during this outage, although the work could be done as early as December 2009.

The new boiler components will not increase the capacity of the boiler to produce steam or to burn RLS. The maximum permitted heat input rate to the boiler will not change.

The replacement steam drum is expected to have the following specifications:

- 58-1/8 inch inside diameter (ID), 28 feet height, 3-7/16 inch wall thickness;
- Materials of construction – high strength carbon steel; and
- Design pressure – 1,100 pounds per square inch (psi).

The replacement mud drum is expected to have the following specifications:

- 46-7/8 inch ID, 26 feet height, 2-3/4 inch wall thickness;
- Materials of construction – high strength carbon steel; and
- Design pressure – 1,100 psi.

The replacement air heater is expected to have the following specifications:

- Cold side:
  - Air temperature to air heater – 200 degrees Fahrenheit (°F); and
  - Air temperature to furnace – 660°F.
- Hot side:
  - Air temperature to air heater – 850°F; and
  - Air temperature out of air heater – 551°F.
- Heating surface – 49,886 square feet.

The air heater replacement will have a similar capacity to the existing air heater. It is expected that the replacement air heater will allow for additional annual boiler operating hours due to less downtime for maintenance; however, no additional RLS firing will result due to the replacement. RLS firing is dependent on pulp production, which will not increase as a result of this project. The additional operating time will allow the boiler to operate at a lower short-term average RLS firing rate while decreasing the thermal cycles associated with startups and shutdowns.

All existing drum internals will be moved from the existing drums to the new drums. In order to accommodate the new steam and mud drum components, Rayonier is proposing to replace the generating bank tubes and make minor modifications to the side wall, outlet duct, rear wall, screen, supply, and roof tubes. Boiler refractory will also be replaced as needed to accommodate these repairs.

2.3 Air Pollution Control Equipment

The Recovery Boiler utilizes a multi-stage wet scrubber for the control of SO_2 and particulate matter (PM) emissions. Non-condensable gases from the red liquor evaporators are also vented to the wet scrubber. The wet scrubber uses ammonium hydroxide as the scrubbing medium. The sulfur dioxide in the flue gas reacts with ammonium hydroxide to form ammonium bisulfite. The ammonium bisulfite solution is drawn off, filtered through sand filters, and pumped to the acid plant and recycled as the base for making the cooking acid used in the digesters.

Additional PM control is provided by a Brinks Demister filter unit. The absorption process that occurs in the scrubber process produces an aerosol type particulate, ammonium bisulfite, which requires the additional control afforded by the filter unit. The Brinks Demister consists of four enclosed rubber-lined metal compartments each containing 52 candles. Each candle is a 12-foot-high cylinder composed of 6 inches of tightly wound polyester fiber held within a concentric wire cage.

A process flow diagram of the Recovery Boiler is presented in Attachment RPF-EU1-I1 of the application form.

3.0 AIR QUALITY REVIEW REQUIREMENTS

3.1 PSD Review Requirements

A PSD applicability analysis was conducted to demonstrate that the proposed project would not trigger PSD review. PSD review is used to determine whether significant air quality deterioration will result from a major new or modified facility. Federal PSD requirements are contained in Title 40, Section 52.21 of the Code of Federal Regulations (40 CFR 52.21), Prevention of Significant Deterioration of Air Quality. The Florida Department of Environmental Protection (FDEP) has adopted PSD regulations that are equivalent to the federal PSD regulations [Rule 62-212.400, Florida Administrative Code (F.A.C.)]. For an existing major stationary source for which a modification is proposed, the modification is subject to PSD review if the net increase in emissions due to the modification is greater than the PSD significant emissions rates (i.e., a "major modification"). The PSD significant emissions rates are listed in Table 3-1.

The determination of whether a significant net increase in emissions will occur is based on comparison of "baseline actual emissions" to "projected actual emissions" for all emissions units affected by the proposed project. "Baseline actual emissions" and "projected actual emissions" are defined in Rules 62-210.200(34) and (215), F.A.C. "Baseline actual emissions" for an existing emissions unit other than an electric utility steam generating unit, is the average rate, in tons per year (TPY), at which the emissions unit actually emitted the pollutant during any consecutive 24-month period, selected by the owner/operator, within the 10-year period immediately preceding the date a complete permit application is received by FDEP. The average rate includes fugitive emissions to the extent quantifiable and emissions associated with startups and shutdowns. The average rate must be adjusted downward to exclude:

- Any non-compliant emissions that occurred while the emissions units were operating above an emissions limitation that was legally enforceable during the consecutive 24-month period.
- Any emissions that would have exceeded an emission limitation with which the major stationary source must currently comply, had such major stationary source been required to comply with such limitations during the consecutive 24-month period.

For projects involving multiple emissions units, only one consecutive 24-month period can be used for all the emissions units being changed. However, a different 24-month period can be used for each PSD pollutant.

Rule 62-210.370, F.A.C., requires a specific methodology for computing baseline actual emissions and net emissions increases. In general, this rule sets forth a hierarchy of emission estimating methods, of which the most accurate method is to be used. Continuous emissions monitoring systems (CEMS) are generally recognized as the most accurate method, followed by mass balance calculations, followed by emission factors. If stack test data are used, the emission factor shall be based on the average emissions per unit of input, output, or gas volume, whichever is appropriate, of all valid tests conducted during at least a 5-year period encompassing the period over which the emissions are computed, provided all stack tests used shall represent the same operational and physical configuration of the unit.

"Projected actual emissions" is the maximum annual rate, in TPY, at which an existing emissions unit is projected to emit a regulated air pollutant in any one of the 5 years following the date the unit resumes regular operation after the project, or in any one of the 10 years following that date, if the project involves increasing the emissions unit's potential to emit that regulated air pollutant, and full utilization of the unit would result in a significant emissions increase or a significant net emissions increase at the facility.

In determining the projected actual emissions, FDEP shall consider all relevant information, including historical operating data, the company's own representations, the company's expected business activity, the company's filings with the state or federal regulatory authorities, and compliance plans or orders. Fugitive emissions, to the extent quantifiable, and emissions associated with startups and shutdowns shall be considered.

The projected actual emissions shall exclude 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, and that are also unrelated to the particular project, including any increased utilization due to demand growth (this is referred to as the "demand growth exclusion"). The U.S. Environmental Protection Agency's (EPA's) final PSD rule revisions, promulgated on December 31, 2002, state:

> *That is, under today's new provisions for non-routine physical or operational changes to existing emissions units, rather than basing a unit's post-change emissions on its PTE, you may project an annual rate, in TPY, that reflects the maximum annual emissions rate that will occur during any one of the 5 years immediately after the physical or operational change. ...This projection of the unit's annual emissions rate following the change is defined as the "projected actual emissions", and will be based on your maximum annual rate in tons per year at which you are projected to emit a regulated NSR pollutant, less any amount of*

> *emissions that could have been accommodated during the selected 24-month baseline period and is not related to the change. Accordingly, you will calculate the unit's projected actual emissions as the product of: (1) The hourly emissions rate, which is based on the operational capabilities following the change(s), taking into account legally enforceable restrictions that could affect the hourly emissions rate following the change(s); and (2) the projected level of utilization, which is based on both the emissions unit's historical annual utilization rate and available information regarding the emissions units' likely post-change capacity utilization. ...From the initial calculation, you may then make the appropriate adjustment to subtract out any portion of the emissions increase that could have been accommodated during the unit's 24-month baseline period and is unrelated to the change.*
>
> *[Federal Register, Vol. 67, pg. 80196]*
>
> *Consequently, under today's new rules, when a projected increase in equipment utilization is in response to a factor such as the growth in market demand, you may subtract the emission increases from the unit's projected actual emissions if: (1) The unit could have achieved the necessary level of utilization during the consecutive 24-month period you selected to establish the baseline actual emission; and (2) the increase is not related to the physical or operational change(s) made to the unit. [Federal Register, Vol. 67, pg. 80203]*

Further explanation was provided in the preamble to EPA's proposed PSD rule revisions on September 14, 2006:

> *That is, the source can emit up to its current maximum capacity without triggering major NSR under the actual-to-projected-actual test, as long as the increase is unrelated to the change. [Federal Register, Vol. 71, pg. 54237]*
>
> *Post-change emissions are generally projected using the emissions unit's maximum annual rate, in tons per year, at which it is expected to emit a regulated NSR pollutant within 5 years following a change, less any amount of emissions that the unit could have accommodated during the selected 24-month baseline period and that are unrelated to the change. This final "projected actual" value, in tons per year, is the value you compare to the "baseline actual emissions" in order to determine...whether the proposed project will result in a "significant" emissions increase, as defined in the first step of the calculation.*
>
> *[Federal Register, Vol. 71, pg. 54238]*

If the proposed modification results in a significant emissions increase for any PSD pollutant, then all contemporaneous increases or decreases in emissions of that pollutant, which have occurred at the facility in the last 5 years, must also be considered.

The Rayonier facility is an existing major stationary facility because potential emissions of at least one PSD-regulated pollutant exceed 100 TPY (for example, potential SO_2 emissions currently exceed 100 TPY). Therefore, PSD review is required for any pollutant for which the net increase in emissions due to a modification is greater than the PSD significant emissions rates (see Table 3-1). If a modification meets these criteria, it is deemed a "major modification".

3.2 National Emission Standards for Hazardous Air Pollutants

The existing Recovery Boiler is subject to the National Emission Standards for Hazardous Air Pollutants (NESHAP) for Chemical Recovery Combustion Sources at Kraft, Soda, Sulfite, and Stand-Alone Semichemical Pulp Mills contained in 40 CFR 63, Subpart MM. In addition to the monitoring, recordkeeping, and reporting requirements, the Recovery Boiler is subject to the PM emission limit for existing sources contained in 40 CFR 63.862(a)(2).

The Maximum Achievable Control Technology (MACT) General Provisions, in 40 CFR 63.2, define a new source as, "...any affected source the construction or reconstruction of which is commenced after the Administrator first proposes a relevant emission standard under this part." The Recovery Boiler was constructed prior to the proposal date for this NESHAP. Therefore, the Recovery Boiler is an existing source, unless it is "reconstructed." Under the MACT General Provisions (40 CFR 63, Subpart A), *reconstruction* is defined below as follows:

Reconstruction, unless otherwise defined in a relevant standard, means the replacement of components of an affected or previously non-affected source to such an extent that:

1. The fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable new source.
2. It is technologically and economically feasible for the reconstructed source to meet the relevant standard(s) established by the Administrator pursuant to Section 112 of the Act. Upon reconstruction, an affected source, or a stationary source that becomes an affected source, is subject to relevant standards for new sources, including compliance dates, irrespective of any change in emission of hazardous air pollutants from that source.

The estimated cost of the proposed changes to the Recovery Boiler is $7,000,000. The estimated cost of constructing a new recovery boiler of comparable size to the Recovery Boiler is more than $100 million. Therefore, the planned changes are expected to cost well below the 50-percent cost threshold that defines "reconstruction."

TABLE 3-1
PSD SIGNIFICANT EMISSION RATES AND *DE MINIMIS* MONITORING CONCENTRATIONS

Pollutant	Significant Emission Rate (TPY)	*De Minimis* Monitoring Concentration[a] (μg/m³)
Sulfur Dioxide	40	13, 24-hour
Particulate Matter [PM(TSP)]	25	NA
Particulate Matter (PM_{10})	15	10, 24-hour
Particulate Matter ($PM_{2.5}$)	10	NA
Nitrogen Dioxide	40	14, annual
Carbon Monoxide	100	575, 8-hour
Volatile Organic Compounds (Ozone)	40	100 TPY[b]
Lead	0.6	0.1, 3-month
Sulfuric Acid Mist	7	NM
Total Fluorides	3	0.25, 24-hour
Total Reduced Sulfur	10	10, 1-hour
Reduced Sulfur Compounds	10	10, 1-hour
Hydrogen Sulfide	10	0.2, 1-hour
Mercury	0.1	0.25, 24-hour
MWC Organics	3.5×10^{-6}	NM
MWC Metals (as PM)	15	NM
MWC Acid Gases (SO_2 + HCl)	40	NM
MSW Landfill Gases	50	NM

Note: Ambient monitoring requirements for any pollutant may be exempted if the impact of the increase in emissions is less than *de minimis* monitoring concentrations.

NA = Not applicable.
NM = No ambient measurement method established; therefore, no *de minimis* concentration has been established.
μg/m³ = micrograms per cubic meter.
MWC = Municipal waste combustor
MSW = Municipal solid waste

[a] Short-term concentrations are not to be exceeded.
[b] No *de minimis* concentration; an increase in VOC emissions of 100 TPY or more will require a monitoring analysis for ozone.

Sources: 40 CFR 52.21.
Rule 62-212.400, F.A.C.

4.0 AIR EMISSIONS

4.1 Baseline Actual Emissions

The past actual (baseline actual) annual average emissions for the Recovery Boiler are presented in Table 4-1. The basis of the emissions estimates are presented in Appendix A. Based on recently adopted Florida PSD reform rules, the baseline actual emissions are based on a consecutive 24-month period out of the last 10 years. Actual emissions for each of these 10 years (1999 to 2008) were determined based on operating data, available stack test data, and emission factors. For each pollutant, the consecutive 2-year period with the highest average annual (TPY) emissions was selected as the baseline actual emissions for the Recovery Boiler. The 2-year averages used for each pollutant are as follows:

Sulfur Dioxide – SO_2	1999 to 2000
Nitrogen Oxides – NO_x	2004 to 2005
Carbon Monoxide – CO	2007 to 2008
Particulate Matter – PM	2005 to 2006
Particulate Matter under 10 microns in diameter – PM_{10}	2005 to 2006
Particulate Matter under 2.5 microns in diameter – $PM_{2.5}$	2005 to 2006
Volatile Organic Compounds – VOC	2004 to 2005
Sulfuric Acid Mist – SAM	1999 to 2000
Lead – Pb	2000 to 2001
Mercury – Hg	2000 to 2001
Fluorides – F	2000 to 2001

The baseline actual emissions for the Recovery Boiler shown in Table 4-1 and Appendix A may differ from the annual emissions shown in the Annual Operating Reports (AORs) submitted to FDEP by Rayonier, as described below. The AOR data for 1999-2008 for the Recovery Boiler are presented in Appendix B for reference.

The revised emission factors used for determining the baseline actual emissions are shown in Appendix A, Table A-3. The emission factors used in the previous AORs were revised to reflect any current AP-42 emission factors, as well as the emissions reporting hierarchy required by Rule 62-210.370, F.A.C. No adjustments were required to reflect non-compliance emissions, as all emissions were in compliance with permit limits during this period.

The Florida rules require that, if stack test data are used, the emission factor shall be based on the average emissions per unit of input, output, or gas volume, whichever is appropriate, of all valid tests conducted during at least a 5-year period encompassing the period over which the emissions are computed, provided all stack tests used shall represent the same operational and physical configuration of the unit. To determine the operational and physical configuration of the Recovery Boiler for each year during the past 10 years, the permitting files were researched. It was concluded that the Recovery Boiler has had the same operational/physical configuration over all the years for which stack tests are used to determine the baseline emissions.

In cases where 5 years of stack tests data were not available for a particular pollutant, however, it may still be appropriate to use the stack test data as being the most representative emission factor, as opposed to a general published emission factor.

The resulting baseline actual emissions for each pollutant for each year, based on the revised emission factors, are presented in Appendix A, Table A-4. The resulting 2-year average emissions for each 2-year period during the last 10 years are presented in Appendix A, Table A-5. The highest 2-year average for each pollutant represents the baseline actual emissions: see Table 4-1 and Appendix A, Table A-5.

4.1.1 Sulfur Dioxide

The Recovery Boiler is equipped with a CEMS for SO_2. The annual SO_2 emissions reported in the past AORs for RLS firing are based on the total SO_2 emissions from the CEMS minus the SO_2 emissions calculated for No. 6 fuel oil firing (see Appendix B, Table B-1). CEMS data are recognized as the most accurate method for determining emissions; therefore, the values reported in the AORs were retained as the total annual SO_2 emissions from the Recovery Boiler (see Appendix A, Tables A-3 and A-4). The total emissions were then used to determine emissions from RLS burning and emissions from No. 6 fuel oil burning.

The SO_2 emission factor for firing No. 6 fuel oil for the AOR reporting years 1999 and 2000 was based on an assumed scrubber efficiency of 90 percent and the stoichiometric calculation where all fuel oil sulfur content is assumed to be converted to SO_2. The SO_2 emission factor for firing No. 6 fuel oil for the AOR reporting years 2001 to 2008 was based on the calculated scrubber efficiency and the stoichiometric calculation where fuel oil sulfur content is assumed to be converted to SO_2. The scrubber efficiency was calculated based on SO_2 scrubber input and scrubber SO_2 emissions as determined by the CEMS monitor. SO_2 input to the wet scrubber was calculated based on RLS sulfur content and uncontrolled No. 6 fuel oil SO_2 emissions. The calculated scrubber efficiency for SO_2 ranged from 96 to 98 percent. The annual fuel oil usage rate was used with these emission factors to determine the annual SO_2 emissions from the Recovery Boiler due to No. 6 fuel oil firing (see Appendix A, Table A-3).

SO_2 emissions from No. 6 fuel oil were then subtracted from the total SO_2 emissions to obtain SO_2 emissions due to RLS firing for each year from 1999 to 2008. Emissions for the 2-year period of 1999 to 2000 were selected for the baseline actual SO_2 emissions (see Table 4-1 and Appendix A, Table A-5).

4.1.2 Nitrogen Oxides

Annual emissions for NO_x for AOR reporting years 1999 to 2003 due to RLS firing were based on a 1995 stack test average emission rate of 245 lb/hr. For the 2004 AOR, NO_x emissions from the Recovery Boiler for RLS firing was based on 525 lb/hr, which was the average emission rate from a stack test conducted that year. Annual emissions for AOR reporting years 2005 to 2008 for RLS firing were based on 501.4 lb/hr, which was the average emission rate from stack testing conducted in 2005.

Rule 62-210.370(2)(d)1.a., F.A.C., requires that when using annual stack test results to calculate baseline actual emissions, a minimum 5-year period that encompasses the 2-year period for which emissions estimates are being made must be used, if adequate data are available. The stack test report for the NO_x testing conducted in 1995 is no longer available, and the operating rate during the testing could not be verified. The tested emission rate is also much lower than the 2004 and 2005 testing. Therefore, the 1995 stack test was considered non-representative, and was not considered to determine baseline actual emissions.

To determine baseline actual emissions for 1999 to 2008, the emission rates from the stack tests conducted in 2004 and 2005 were used (see Appendix A, Table A-1). Although a 5-year average of stack tests is not available, the two stack tests from 2004 and 2005 are the most representative emissions data for the Recovery Boiler. Using the stack test average NO_x emissions in pounds per ton (lb/ton) of RLS, the average NO_x emissions in lb/ton of RLS were determined (see Appendix A, Table A-4). This factor was applied to the tons of RLS burned to determine the annual NO_x emissions for each year (1999 to 2008) (see Appendix A, Tables A-3 and A-4).

The NO_x emission factor used in the past AOR reporting due to No. 6 fuel oil firing was 47 pounds per thousand gallons (lb/10^3 gal) from AP-42, Table 1.3-1. This is the current AP-42 emission factor, and was used for all years in the revised emissions factors table (see Appendix A, Table A-3). The annual No. 6 fuel oil usage rate was used with this emission factor to determine the annual NO_x emissions from the Recovery Boiler due to fuel oil firing.

Annual emissions of NO_x due to RLS and No. 6 fuel oil firing were summed to determine total annual NO_x emissions from the Recovery Boiler. Emissions for the 2-year period of 2004 to 2005 were selected for the baseline actual NO_x emissions (see Table 4-1 and Appendix A, Table A-5).

4.1.3 Carbon Monoxide

Rayonier maintains a process monitor for CO on the Recovery Boiler, and the annual CO emissions reported in the past AORs are based on the process monitor data. However, the process monitor for CO emissions is not a certified CEMS unit, but it is routinely calibrated. CO emissions from RLS firing reported in the past AORs were based on the total CO process monitor emission rate minus CO emissions calculated for No. 6 fuel oil firing (see Appendix B, Table B-1).

The values reported annually in the AORs were revised for the baseline actual emissions as the 5-year average of annual CO emissions from the Recovery Boiler. To determine actual emissions for 1999, the year 1999 and the subsequent 4 years (2000 to 2003) were used (see Appendix A, Table A-1). Using the average CO emissions in lb/ton of RLS fired, the 5-year average CO emissions in lb/ton of RLS were determined (see Appendix A, Table A-1). Using the annual tons of RLS burned, the annual emissions for 1999 were then determined (see Appendix A, Table A-4). This process was repeated for all years to determine the CO emissions from RLS.

The CO emission factor used in the past AOR reporting for firing No. 6 fuel oil was 5.0 lb/10^3 gal from AP-42, Table 1.3-1. This is the current AP-42 emission factor, and was used for all years in the revised emission factors table (see Appendix A, Table A-4). The annual No. 6 fuel oil usage rate was used with this emission factor to determine the annual CO emissions from the Recovery Boiler due to fuel oil firing.

Annual emissions of CO due to RLS burning were determined by subtracting the CO emissions due to No. 6 fuel oil firing from the total annual CO emissions from the Recovery Boiler.

Emissions for the 2-year period of 2007 to 2008 were selected for the baseline actual CO emissions (see Table 4-1 and Appendix A, Table A-5).

4.1.4 Particulate Matter

The PM emission factor used in the past AOR reporting for RLS firing ranged from 0.60 to 3.26 lb/ton of RLS fired, based on stack test data (see Appendix A, Table A-1 and Appendix B, Table B-1). The revised emission factors for PM were based on the historic stack test data from the Recovery Boiler, as shown in Appendix A, Table A-1. The revised emission factors are shown in Table A-3. The average emission rate for the stack test conducted in 2000 was 3.26 lb/ton of RLS. The average emission rates for the other stack tests conducted between 1999 and 2008 ranged from 0.60 to 0.79 lb/ton of RLS. Therefore, it was concluded that the PM emission rate from the stack testing conducted in 2000 was not representative of normal operation.

Rule 62-210.370(2)(d)1.a., F.A.C., requires that when using annual stack test results to calculate baseline actual emissions, a minimum 5-year period that encompasses the 2-year period for which emissions estimates are being made must be used, if adequate data are available. To comply with this requirement, to determine actual emissions for 1999, the year 1999 and the subsequent 4 years (2000 to 2004) were used (see Appendix A, Table A-3). Using the average PM emissions in lb/ton of RLS fired, the 5-year average PM emissions in lb/ton of RLS were determined (see Appendix A, Table A-1). Using the annual tons of RLS fired, the annual emissions for 1999 were then determined (see Appendix A, Table A-4). This process was repeated for all years to determine the PM emissions from RLS.

Rule 62-210(36), F.A.C., which is the definition of "Baseline actual emissions," also requires that the emissions be adjusted downward to exclude any emissions that would have exceeded an emission limitation with which the major stationary source must currently comply, had such major stationary source been required to comply with such limitations during the consecutive 24-month period. The current maximum permitted PM emission rate for the Recovery Boiler, as required by 40 CFR 63, Subpart MM, is 0.040 grain per dry standard cubic foot (gr/dscf) at 8 percent oxygen (O_2). This rule went into effect on March 13, 2004. Therefore, any stack tests that resulted in a PM emission rate above 0.040 gr/dscf at 8 percent O_2 must be reduced to 0.040 gr/dscf. However, as shown in Table A-1, there were no stack tests that exceeded 0.040 gr/dscf at 8 percent O_2; therefore, no adjustments were necessary.

The PM emission factor used in the past AOR reporting for No. 6 fuel oil firing was 9.19(S) + 3.22 lb/10^3 gal based on AP-42 Table 1.3-1, and 90-percent removal in the scrubber, where S is the actual sulfur content as reported for each year in the AORs. This is the current AP-42 emission factor, and was used for all years in the revised emission factors table (see Appendix A, Table A-3). The annual No. 6 fuel oil usage rate was used with this emission factor to determine the annual PM emissions from the Recovery Boiler due to fuel oil firing.

PM_{10} emissions reported from No. 6 fuel oil firing in the AORs were based on 7.17 × (1.12 S + 0.37) lb/10^3 gal. $PM_{2.5}$ emissions reported from No. 6 fuel oil firing in the 2008 AOR were based on 77 percent of PM. The emission factors of 100 percent and 97 percent of PM emissions for PM_{10} and $PM_{2.5}$, respectively, were used for the revised factors for No. 6 fuel oil firing for all years, based on AP-42, Table 1.3-4 (see Appendix A, Table A-3).

PM_{10} emissions reported from RLS burning in the AORs were based on 89 percent of the PM emissions. $PM_{2.5}$ emissions from RLS burning in the 2008 AOR were based on 77 percent of the PM emissions. The revised emissions factors used were 90.7 percent and 73.7 percent of PM emissions for PM_{10} and $PM_{2.5}$, respectively, from NCASI Technical Bulletin No. 884, Table 5.3 for sulfite recovery furnaces (see Appendix A, Table A-3). These factors were applied to the PM emission factor for each year to obtain PM_{10} and $PM_{2.5}$ emissions from RLS firing (see Appendix A, Table A-5).

Annual emissions of PM, PM_{10}, and $PM_{2.5}$ due to RLS and No. 6 fuel oil firing were summed to determine total annual emissions from the Recovery Boiler. Emissions for the 2-year period of 2005 to 2006 were selected for the baseline actual PM, PM_{10}, and $PM_{2.5}$ emissions (see Table 4-1 and Appendix A, Table A-5).

4.1.5 Volatile Organic Compounds

The VOC emission factor used for RLS firing in AOR reporting years 1999 to 2003 was based on 3.5 lb/ton air-dried unbleached pulp (ADUP). The VOC emission factor used for RLS firing in AOR reporting years 2004 to 2008 was based on annual methanol stack testing.

Evaporator vent gases containing methanol from the Evaporator Vents Methanol Condenser System (EU 021) as well as steam that is used to eject the vent gases from the two sets of multiple effect evaporators are sent to the multi-stage wet scrubber system that serves the Recovery Boiler. This is the primary source of methanol in the flue gas. NCASI Technical Bulletin No. 884 provides emissions data for methanol and VOCs from ammonia-based sulfite recovery boilers. The VOC emissions data provided in the bulletin were determined by EPA Method 25A. The NCASI technical bulletin data shows that VOCs from the Recovery Boiler are 20.6 percent of methanol emissions.

Rule 62-210.370(2)(d)1.a., F.A.C., requires that when using annual stack test results to calculate baseline actual emissions, a minimum 5-year period that encompasses the 2-year period for which emissions estimates are being made must be used, if adequate data are available. Adequate data for annual methanol stack testing for the Recovery Boiler are available for the years 2003 to 2008. Adequate data for process rates during methanol stack testing are available for the years 2007 and 2008. To comply with this requirement, to determine actual emissions for 1999 to 2007, the year 2003 and subsequent 4 years (2004-2007) were used. To determine actual emissions for 2008, the year 2004 and subsequent 4 years (2005-2008) were used (see Appendix A, Tables A-1 and A-3). Using the average 2007 and 2008 stack test RLS firing rate and the average emissions in lb/hr, the 5-year average methanol emissions in lb/ton of RLS were determined (see Appendix A, Table A-4). Using the annual tons of RLS fired, the annual emissions of methanol for 1999 were then determined (see Appendix A, Table A-4). It was assumed that 20.6 percent of the methanol emissions from the Recovery Boiler were VOC emissions, based on the NCASI data. This process was repeated for all years to determine the VOC emissions from RLS burning.

The VOC emission factor used in the past AOR reporting from No. 6 fuel oil burning was 0.76 lb/10^3 gal from AP-42, Table 1.3-3. This is the current AP-42 emission factor, and was used for all years in the revised emission factors table (see Appendix A, Table A-3). The annual No. 6 fuel oil usage rate was used with this emission factor to determine the annual VOC emissions from the Recovery Boiler due to fuel oil firing.

Annual emissions of VOCs due to RLS and No. 6 fuel oil firing were summed to determine total annual emissions from the Recovery Boiler. Emissions for the 2-year period of 2004 to 2005 were selected for the baseline actual VOC emissions (see Table 4-1 and Appendix A, Table A-5).

4.1.6 Sulfuric Acid Mist

No SAM emission factor has been used in the past AOR reporting for RLS or No. 6 fuel oil (see Appendix B, Table B-1). To determine a SAM emission factor, the ratio of sulfur trioxide (SO_3) and SO_2 emissions for No. 6 fuel oil firing from AP-42 was used, and then multiplied by the ratio of the molecular weights of sulfuric acid (H_2SO_4) and SO_3 (98/80). The resulting SAM emission factor is approximately 4.4 percent of the SO_2 emissions (see Appendix A, Table A-3). The same 4.4-percent factor of SO_2 emissions was used for SAM emissions due to RLS burning. Using the annual SO_2

emissions and the 4.4-percent factor, the annual SAM emissions for each year were determined (see Appendix A, Table A-4). Emissions for the 2-year period of 1999 to 2000 were selected for the baseline actual SAM emissions (see Table 4-1 and Appendix A, Table A-5).

4.1.7 Lead

No Pb emissions have been reported in past AORs for RLS firing in the Recovery Boiler (see Appendix B, Table B-1). The revised Pb emission factor used is 9.6×10^{-5} lb/ton of RLS burned, based on NCASI Technical Bulletin 858, Table 15B, for sulfite recovery furnaces.

The Pb emission factor used in the past AOR reporting for No. 6 fuel oil firing was 0.016 lb/hr. The revised emission factor used for all years is 1.5×10^{-3} lb/10^3 gal of No. 6 fuel oil from AP-42, Table 1.3-11 (see Appendix A, Table A-3).

Using the annual tons of RLS fired and fuel oil burning rates (from the AOR data), the annual Pb emissions for each year were determined (refer to Appendix A, Table A-4). Emissions for the 2-year period of 2000 to 2001 were selected for the baseline actual Pb emissions (see Table 4-1 and Appendix A, Table A-5).

4.1.8 Mercury

No Hg emissions have been reported in past AORs (see Appendix A, Table A-1). The revised emission factor used for RLS firing is 4.70×10^{-6} lb/ton of RLS burned, based on NCASI Technical Bulletin 858, Table 15B for sulfite recovery furnaces. The revised emission factor used for firing fuel oil is 1.13×10^{-4} lb/10^3 gal of No. 6 fuel oil burned from AP-42, Table 1.3-11.

Using the annual RLS and fuel oil burning rates (from the AOR data), the annual Hg emissions for each year were determined (refer to Appendix A, Table A-4). Emissions for the 2-year period of 2000 to 2001 were selected for the baseline actual Hg emissions (see Table 4-1 and Appendix A, Table A-5).

4.1.9 Fluorides

No F emissions have been reported in past AORs (see Appendix A, Table A-1). No F emission factors exist for RLS burning in recovery furnaces; therefore, no F emissions were calculated for RLS burning for the baseline actual emissions. The revised emission factor for No. 6 fuel oil burning is 0.0373 lb/10^3 gal based on AP-42, Table 1.3-11 (see Appendix A, Table A-3).

Using the fuel oil burning rates (from the AOR data), the annual emissions for each year were determined (refer to Appendix A, Table A-4). Emissions for the 2-year period of 2000 to 2001 were selected for the baseline actual F emissions (see Table 4-1 and Appendix A, Table A-5).

4.2 Projected Actual Emissions

"Projected actual emissions" for the Recovery Boiler were developed considering the operating factors and emission factors used for the baseline actual emissions. The emission factors used to calculate the projected actual emissions were the same emission factors used to calculate the baseline actual emissions, except for the following:

- SO_2 emission factor for RLS and fuel oil burning,
- CO emission factor for RLS burning,
- PM emission factor for RLS burning,
- VOC emission factor for RLS burning, and
- Scrubber efficiency for PM emissions from No. 6 fuel oil firing.

The SO_2 emission rate in lb/ton of RLS burned has been trending downward since 1999 (see Appendix A, Table A-1). Therefore, the SO_2 emission factor used to calculate the projected actual emissions from the Recovery Boiler while burning RLS was based on the maximum CEMS emission rate within the last 5 years, in lb/ton of RLS fired (refer to Appendix A, Table A-1) The SO_2 emission factor used to calculate the projected actual emissions from fuel oil burning was based on AP-42, Table 1.3-1, normal firing. The fuel oil sulfur content used was 2.4 percent, based on the maximum fuel oil sulfur content since 1999 (see Appendix A, Table A-2) and assuming a scrubber efficiency of 96 percent.

The CO emission factor used to calculate the projected actual emissions was based on the maximum 5-year average process monitor emission rate in lb/ton of RLS fired from the last 10 years. The PM emission factor used to calculate the projected actual emissions was based on the maximum 5-year average stack test value from the last 10 years. The VOC emission factor was based on the maximum 5-year average methanol stack test value and the 20.6-percent ratio of VOC to methanol emissions from NCASI Technical Bulletin 884. Refer to Appendix A, Table A-1.

The operating factors used to calculate the projected actual emissions were based on the historic maximum total annual heat input to the Recovery Boiler. Historic annual RLS and No 6 fuel oil usage, from the AORs, and the historic annual tons of RLS burned are presented in Appendix A, Table A-2. The projected actual RLS firing rate was based on the historic maximum annual RLS firing rate (see Appendix A, Table A-2).

To determine the projected actual annual No. 6 fuel oil usage, the projected actual heat input due to RLS firing was subtracted from the maximum total annual heat input to the boiler (1999 to 2008). The remaining heat input value was divided by the fuel heat content of 151 MMBtu per thousand gallons, for No. 6 fuel oil, to determine the projected actual annual fuel oil usage.

A scrubber efficiency of 90 percent was used to calculate the projected actual emissions of PM for firing No. 6 fuel oil.

Projected actual annual emissions for the Recovery Boiler are shown in Table 4-2.

4.3 Post-Change Actual Emissions

The "post-change actual emissions" for the Recovery Boiler were based on the maximum emissions that the Recovery Boiler could have accommodated during the baseline period. In order to determine the post-change actual annual RLS firing rate that the boiler could have accommodated, the daily 1-hour average RLS firing rates from January 2006 through August 2009 were reviewed. Using the daily 1-hour average RLS firing rates, the monthly total RLS firing rates were determined. The maximum monthly total RLS firing rate was determined to be 48,610,000 pounds. The maximum monthly total was then used to determine the average daily RLS firing rate. The average daily RLS firing rate was then annualized based on 358 days per year operation. This results in an annual RLS firing rate of 280,688 TPY. With this level of heat input to the boiler, it is assumed the boiler could not accommodate any further fuel oil firing. However, where the pollutant emissions factor is higher for fuel oil burning than RLS burning, a portion of the heat input from fuel oil was assumed. For these pollutants, the post-change actual annual No. 6 fuel oil usage was based on the maximum annual usage reported in the AORs from 1999 through 2008.

The emission factors for SO_2, VOC, SAM, Pb, Hg, and F due to RLS burning are the same as those used to calculate the projected actual emissions. The emission factors for PM and NO_x are based on the maximum annual stack test value from the last 10 years (see Appendix A, Table A-1). The emission factor for CO is based on the maximum annual average process monitor CO emission rate from the last 10 years (see Appendix A, Table A-1). The emission factors for No. 6 fuel oil firing are the same as those used to calculate the projected actual emissions.

Post-change actual annual emissions for the Recovery Boiler are presented in Table 4-3. These are the emissions the Recovery Boiler was capable of accommodating during the baseline emissions period.

4.4 Demand Growth Exclusion Calculation

The emissions due to demand growth can be excluded from the PSD applicability analysis for the Recovery Boiler. The demand growth emissions are calculated by subtracting the projected actual emissions (see Table 4-2) from the post-change actual emissions (see Table 4-3). The demand growth exclusion emissions are shown in Table 4-4.

4.5 Fugitive and Startup/Shutdown Emissions

Fugitive emissions from the Recovery Boiler have not been quantified, as there is no reasonable method to quantify these emissions.

Emissions from startup and shutdown of the Recovery Boiler have also not been estimated, as the number of startups and shutdowns of the Recovery Boiler are not expected to increase, and may actually decrease, as a result of the project. However, process monitor and CEMS data used to develop annual CO and SO_2 emission factors for baseline and projected actual emissions do include emissions due to startup and shutdown.

4.6 Effects on Other Emissions Units

No other emissions units at the Rayonier facility will be affected by the Recovery Boiler project. No additional RLS will be processed, and no additional ADUP will be produced.

4.7 PSD Review

The Rayonier facility is considered to be an existing major stationary facility because potential emissions of at least one PSD-regulated pollutant exceed 100 TPY (for example, potential SO_2 emissions currently exceed 100 TPY). Therefore, PSD review is required for any pollutant for which the net increase in emissions due to the modification is greater than the PSD significant emissions rates.

The net increases in emissions due to the proposed project at the Rayonier facility are summarized in Table 4-5. For the Recovery Boiler, the baseline actual emissions and projected actual emissions are based on information from Tables 4-1 and 4-2, respectively. The post-change actual emissions are based on information from Table 4-3. The "demand growth exclusion" represents the additional emissions that the Recovery Boiler could have accommodated during the baseline period, as shown in Table 4-4.

As shown in Table 4-5, the increase in emissions due to the project does not exceed the PSD significant emission rate for any pollutant. Therefore, PSD review does not apply to the proposed project.

TABLE 4-1
BASELINE ACTUAL EMISSIONS
RAYONIER PERFORMANCE FIBERS, FERNANDINA BEACH, FLORIDA

Source Description		EU ID	Highest 2-Year Average Calculation (TPY) Year 1	Year 2	Average
Sulfur Dioxide - SO_2			**1999**	**2000**	**'99 - '00**
- Recovery Boiler		*006*	950.44	1,067.23	1,008.84
	Total:		**950.44**	**1,067.23**	**1,008.84**
Nitrogen Oxides - NO_X			**2004**	**2005**	**'04 - '05**
- Recovery Boiler		*006*	1,941.36	2,013.56	1,977.46
	Total:		**1,941.36**	**2,013.56**	**1,977.46**
Carbon Monoxide - CO			**2007**	**2008**	**'07 - '08**
- Recovery Boiler		*006*	608.95	751.00	679.97
	Total:		**608.95**	**751.00**	**679.97**
Particulate Matter Total - PM			**2005**	**2006**	**'05 - '06**
- Recovery Boiler		*006*	90.82	91.55	91.19
	Total:		**90.82**	**91.55**	**91.19**
Particulate Matter - PM_{10}			**2005**	**2006**	**'05 - '06**
- Recovery Boiler		*006*	82.53	83.18	82.85
	Total:		**82.53**	**83.18**	**82.85**
Particulate Matter - $PM_{2.5}$			**2005**	**2006**	**'05 - '06**
- Recovery Boiler		*006*	67.32	67.83	67.57
	Total:		**67.32**	**67.83**	**67.57**
Volatile Organic Compounds - VOC			**2004**	**2005**	**'04 - '05**
- Recovery Boiler		*006*	8.28	8.61	8.45
	Total:		**8.28**	**8.61**	**8.45**
Sulfuric Acid Mist - SAM			**1999**	**2000**	**'99 - '00**
- Recovery Boiler		*006*	41.82	38.40	40.11
	Total:		**41.82**	**46.96**	**44.39**
Lead - Pb			**2000**	**2001**	**'00 - '01**
- Recovery Boiler		*006*	1.40E-02	1.34E-02	1.37E-02
	Total:		**1.40E-02**	**1.34E-02**	**1.37E-02**
Mercury - Hg			**2000**	**2001**	**'00 - '01**
- Recovery Boiler		*006*	7.59E-04	7.18E-04	7.38E-04
	Total:		**7.59E-04**	**7.18E-04**	**7.38E-04**
Fluorides - F			**2000**	**2001**	**'00 - '01**
- Recovery Boiler		*006*	0.070	0.061	0.066
	Total:		**0.070**	**0.061**	**0.066**

TABLE 4-2
PROJECTED ACTUAL EMISSIONS
RAYONIER PERFORMANCE FIBERS, FERNANDINA BEACH, FLORIDA

Pollutant	Emission Factor	Ref.	Activity Factor	Ref.	Annual Emissions (TPY)
Sulfur Dioxide - SO_2					
- Recovery Boiler (EU 006)	15.36 lb/10^3 gal No. 6 Fuel Oil	1	1,830 10^3 gal/yr	3	14.05
	6.54 lb/ton RLS	2	251,575 ton RLS/yr	4	822.70
				Total:	**836.75**
Nitrogen Oxides - NO_x					
- Recovery Boiler (EU 006)	47 lb/10^3 gal No. 6 Fuel Oil	1	1,830 10^3 gal/yr	3	43.01
	15.67 lb/ton RLS	5	251,575 ton RLS/yr	4	1,970.55
				Total:	**2,013.56**
Carbon Monoxide - CO					
- Recovery Boiler (EU 006)	5 lb/10^3 gal No. 6 Fuel Oil	1	1,830 10^3 gal/yr	3	4.58
	6.10 lb/ton RLS	14	251,575 ton RLS/yr	4	767.66
				Total:	**772.24**
Particulate Matter Total - PM					
- Recovery Boiler (EU 006)	2.53 lb/10^3 gal No. 6 Fuel Oil	1	1,830 10^3 gal/yr	3	2.31
	0.75 lb/ton RLS	6	251,575 ton RLS/yr	4	93.93
				Total:	**96.24**
Particulate Matter - PM_{10}					
- Recovery Boiler (EU 006)	100 % of PM from No. 6 Fuel Oil	7	-- --	--	2.31
	90.7 % of PM from RLS	8	-- --	--	85.19
				Total:	**87.51**
Particulate Matter - $PM_{2.5}$					
- Recovery Boiler (EU 006)	97 % of PM from No. 6 Fuel Oil	7	-- --	--	2.24
	73.7 % of PM from RLS	8	-- --	--	69.22
				Total:	**71.47**
Volatile Organic Compounds - VOC					
- Recovery Boiler (EU 006)	0.28 lb/10^3 gal No. 6 Fuel Oil	13	1,830 10^3 gal/yr	3	0.26
	0.07 lb/ton RLS	6	251,575 ton RLS/yr	4	8.55
				Total:	**8.81**
Sulfuric Acid Mist - SAM					
- Recovery Boiler (EU 006)	4.4 % of SO_2 from No. 6 Fuel Oil	9	-- --	--	0.63
	4.4 % of SO_2 from RLS	9	-- --	--	36.59
				Total:	**37.21**
Lead - Pb					
- Recovery Boiler (EU 006)	1.51E-03 lb/10^3 gal No. 6 Fuel Oil	10	1,830 10^3 gal/yr	3	1.38E-03
	9.6E-05 lb/ton RLS	11	251,575 ton RLS/yr	4	1.21E-02
				Total:	**1.35E-02**
Mercury - Hg					
- Recovery Boiler (EU 006)	1.13E-04 lb/10^3 gal No. 6 Fuel Oil	10	1,830 10^3 gal/yr	3	1.03E-04
	4.70E-06 lb/ton RLS	12	251,575 ton RLS/yr	4	5.91E-04
				Total:	**6.95E-04**
Fluorides - F					
- Recovery Boiler (EU 006)	0.0373 lb/10^3 gal No. 6 Fuel Oil	10	1,830 10^3 gal/yr	3	0.034
	-- lb/ton RLS	--	-- --	--	--
				Total:	**0.034**

Notes:
RLS = Red liquor solids
ADUP = air-dried unbleached pulp
ULSD = Ultra low sulfur diesel fuel (No. 2 fuel oil)

References:
1. AP-42, Table 1.3-1, normal firing. Fuel oil sulfur content set at 2.4%, based on the maximum sulfur content since 1999 (see Appendix A), and assuming scrubber efficiency of 90% for PM and 96% for SO_2.
2. Based on highest historic emission rate (2004-2008). Emission rate based on continuous monitor and process data as reported in AORs.
3. Based on the maximum annual heat input from fuel oil and RLS combined minus the maximum annual heat input due to RLS firing. Projected actual No. 6 Fuel oil = (4,726,241 MMBtu - (236,053 TPY RLS x 18.66 MMBtu/ton RLS))/151 MMBtu/10^3 gal.
4. Based on the highest annual RLS usage from 1999-2008.
5. Based on average of NOx stack tests conducted 2004 and 2005.
6. Based on maximum 5-year average stack test value.
7. AP-42, Table 1.3-4 for combustion of No. 6 fuel oil with scrubber control. 100% of PM emissions are PM_{10}, 97% of PM emissions are $PM_{2.5}$.
8. NCASI Technical Bulletin No. 884, Table 5.3 (Sulfite Recovery Furnaces, median values).
9. Based on similar derivation of sulfuric acid mist from AP-42, Table 1.3-1, for fuel oil: 3.6% of SO_2 becomes SO_3 then take into account the ratio of sulfuric acid mist and sulfur trioxide molecular weights (98/80).
10. AP-42, Table 1.3-11.
11. NCASI Technical Bulletin No. 858, Table 15B (Sulfite Recovery Furnaces, median values for ND = 0).
12. NCASI Technical Bulletin No. 858, Table 15B (Sulfite Recovery Furnaces, SDln Average). SDln Average is statistically derived sample average applicable to data sets with greater than 50% NDs.
13. AP-42, Table 1.3-3.
14. Based on maximum 5-year average emission rate (1999-2008). Emission rate based on continuous monitor and process data as reported in AORs.

TABLE 4-3
POST-CHANGE ACTUAL EMISSIONS
RAYONIER PERFORMANCE FIBERS, FERNANDINA BEACH, FLORIDA

Pollutant	Emission Factor	Ref.	Annual Activity Factor	Ref.	Max Annual Emissions (TPY)
Sulfur Dioxide - SO_2					
- Recovery Boiler (EU 006)	15.36 lb/10^3 gal No. 6 Fuel Oil	1	0 10^3 gal/yr	--	0.00
	8.71 lb/ton RLS	2	280,688 ton RLS/yr	4	1,221.77
				Total:	**1,221.77**
Nitrogen Oxides - NO_x					
- Recovery Boiler (EU 006)	47 lb/10^3 gal No. 6 Fuel Oil	1	0 10^3 gal/yr	--	0.00
	15.67 lb/ton RLS	5	280,688 ton RLS/yr	4	2,199.57
				Total:	**2,199.57**
Carbon Monoxide - CO					
- Recovery Boiler (EU 006)	5 lb/10^3 gal No. 6 Fuel Oil	1	0 10^3 gal/yr	--	0.00
	8.82 lb/ton RLS	2	280,688 ton RLS/yr	4	1,237.64
				Total:	**1,237.64**
Particulate Matter Total - PM					
- Recovery Boiler (EU 006)	2.53 lb/10^3 gal No. 6 Fuel Oil	1	0 10^3 gal/yr	--	0.00
	0.790 lb/ton RLS	5	280,688 ton RLS/yr	4	110.84
				Total:	**110.84**
Particulate Matter - PM_{10}					
- Recovery Boiler (EU 006)	100 % of PM from No. 6 Fuel Oil	6	-- --	--	0.00
	90.7 % of PM from RLS	7	-- --	--	100.53
				Total:	**100.53**
Particulate Matter - $PM_{2.5}$					
- Recovery Boiler (EU 006)	97 % of PM from No. 6 Fuel Oil	6	-- --	--	0.00
	73.7 % of PM from RLS	7	-- --	--	81.69
				Total:	**81.69**
Volatile Organic Compounds - VOC					
- Recovery Boiler (EU 006)	0.28 lb/10^3 gal No. 6 Fuel Oil	8	0 10^3 gal/yr	--	0.00
	0.07 lb/ton RLS	5	280,688 ton RLS/yr	4	9.54
				Total:	**9.54**
Sulfuric Acid Mist - SAM					
- Recovery Boiler (EU 006)	4.4 % of SO_2 from No. 6 Fuel Oil	9	-- --	--	0.00
	4.4 % of SO_2 from RLS	9	-- --	--	54.34
				Total:	**54.34**
Lead - Pb					
- Recovery Boiler (EU 006)	1.51E-03 lb/10^3 gal No. 6 Fuel Oil	10	3,772 10^3 gal/yr	3	2.85E-03
	9.6E-05 lb/ton RLS	11	250,164 ton RLS/yr	4	1.20E-02
				Total:	**1.49E-02**
Mercury - Hg					
- Recovery Boiler (EU 006)	1.13E-04 lb/10^3 gal No. 6 Fuel Oil	10	3,772 10^3 gal/yr	3	2.13E-04
	4.70E-06 lb/ton RLS	12	250,164 ton RLS/yr	4	5.88E-04
				Total:	**8.01E-04**
Fluorides - F					
- Recovery Boiler (EU 006)	0.0373 lb/10^3 gal No. 6 Fuel Oil	10	3,772 10^3 gal/yr	3	0.070
	-- lb/ton RLS	--	-- --	-- --	
					0.07

Notes:
RLS = Red liquor solids
ADUP = air-dried unbleached pulp

References:
1. AP-42, Table 1.3-1, normal firing. Fuel oil sulfur content set at 2.4%, based on the maximum sulfur content since 1999 (see Appendix A), and assuming scrubber efficiency of 90% for PM and 96% for SO_2.
2. Based on highest historic emission rate (1999-2008). Emission rate based on continuous monitor and process data as reported in AORs.
3. Based on the maximum annual fuel oil usage from 1999-2008.
4. Represents annual RLS firing rate that the Recovery Boiler is capable of accomodating.
   Post change actual annual RLS firing rate based on annualized highest 1-month historic firing rate.
5. Based on maximum historic stack test average emission rate (1999-2008).
6. AP-42, Table 1.3-4 for combustion of No. 6 fuel oil with scrubber control. 100% of PM emissions are PM10, 97% of PM emissions are $PM_{2.5}$.
7. NCASI Technical Bulletin No. 884, Table 5.3 (Sulfite Recovery Furnaces, median values).
8. AP-42, Table 1.3-3.
9. Based on similar derivation of sulfuric acid mist from AP-42, Table 1.3-1, for fuel oil: 3.6% of SO_2 becomes SO_3 then take into account the ratio of sulfuric acid mist and sulfur trioxide molecular weights (98/80).
10. AP-42, Table 1.3-11.
11. NCASI Technical Bulletin No. 858, Table 15B (Sulfite Recovery Furnaces, median values for ND = 0).
12. NCASI Technical Bulletin No. 858, Table 15B (Sulfite Recovery Furnaces, SDln Average).
    SDln Average is statistically derived sample average applicable to data sets with greater than 50% NDs.

TABLE 4-4
DEMAND GROWTH EXCLUSION CALCULATION
RAYONIER PERFORMANCE FIBERS, FERNANDINA BEACH, FLORIDA

Source Description	Pollutant Emission Rate (TPY)										
	SO_2	NO_X	CO	PM	PM_{10}	$PM_{2.5}$	VOC	SAM	Lead	Mercury	Fluoride
Post-Change Actual Emissions [a]											
- *Recovery Boiler (EU 006)*	1,221.8	2,199.6	1,237.6	110.8	100.5	81.7	9.5	54.3	1.49E-02	8.01E-04	7.03E-02
Total- Post-Change Actual	**1,221.8**	**2,199.6**	**1,237.6**	**110.8**	**100.5**	**81.7**	**9.5**	**54.3**	**1.49E-02**	**8.01E-04**	**7.03E-02**
Projected Actual Emissions [b]											
- *Recovery Boiler (EU 006)*	836.8	2,013.6	772.2	96.2	87.5	71.5	8.8	37.2	1.35E-02	6.95E-04	3.41E-02
Total- Projected Actual	**836.8**	**2,013.6**	**772.2**	**96.2**	**87.5**	**71.5**	**8.8**	**37.2**	**1.35E-02**	**6.95E-04**	**3.41E-02**
Demand Growth Exclusion [c]											
- *Recovery Boiler (EU 006)*	385.0	186.0	465.4	14.6	13.0	10.2	0.7	17.1	1.40E-03	1.06E-04	3.62E-02
Total- Demand Growth	**385.0**	**186.0**	**465.4**	**14.6**	**13.0**	**10.2**	**0.7**	**17.1**	**1.40E-03**	**1.06E-04**	**3.62E-02**

Notes:

[a] Based on maximum emissions the emissions unit could have accommodated during the baseline period; see Table 4-3.

[b] Based on annual emissions presented in Table 4-2.

[c] Represents the additional emissions that the unit could have accommodated during the baseline period.

TABLE 4-5
PSD APPLICABILITY ANALYSIS, RECOVERY BOILER PROJECT
RAYONIER PERFORMANCE FIBERS, FERNANDINA BEACH, FLORIDA

Source Description	EU ID	Pollutant Emission Rate (TPY)										
		SO_2	NO_x	CO	PM	PM_{10}	$PM_{2.5}$	VOC	SAM	Lead	Mercury	Fluoride
Post Change Actual Emissions												
- Recovery Boiler	006	1,221.77	2,199.57	1,237.64	110.84	100.53	81.69	9.54	54.34	1.49E-02	8.01E-04	0.07
Demand Growth Exclusion												
- Recovery Boiler	006	385.02	186.02	465.41	14.60	87.51	10.22	0.73	17.12	1.40E-03	1.06E-04	0.036
Projected Actual Emissions												
- Recovery Boiler	006	836.75	2,013.56	772.24	96.24	87.51	71.47	8.81	37.21	1.35E-02	6.95E-04	0.034
Baseline Actual Emissions												
- Recovery Boiler	006	1,008.84	1,977.46	679.97	91.19	82.85	67.57	8.45	40.11	1.37E-02	7.38E-04	0.066
Increase Due to Project		**-172.08**	**36.10**	**92.26**	**5.05**	**4.65**	**3.89**	**0.36**	**-2.90**	**-2.17E-04**	**-4.37E-05**	**-3.15E-02**
PSD SIGNIFICANT EMISSION RATE		40	40	100	25	15	10	40	7	0.6	0.1	3.0
PSD REVIEW TRIGGERED?		No	No	No	No	No	No	No	No	No	No	No

APPENDIX A

BASELINE ACTUAL EMISSIONS CALCULATIONS FOR THE RECOVERY BOILER

TABLE A-1
STACK TESTS AND EMISSIONS DATA FOR THE RECOVERY BOILER
RAYONIER PERFORMANCE FIBERS, FERNANDINA BEACH, FLORIDA

Test Date	PM Emission Rate lb/hr	PM Emission Rate gr/dscf @ 8% O_2	PM Emission Rate corrected lb/hr [a]	PM Process Rate (ton RLS/hr)	PM Emission Factor (lb/ton RLS) [b]	PM 5-year Average Reporting Year	PM 5-year Average Averaging Period	PM 5-year Average Emission Rate lb/hr [c]	PM 5-year Average Process Rate (tons/hr RLS)	PM 5-year Average Emission Factor (lb/ton RLS)	NO_x Emission Rate (lb/hr)	NO_x Process Rate (ton RLS/hr)	NO_x Emission Factor (lb/ton RLS)	NO_x 5-year Average Reporting Year	NO_x 5-year Average Averaging Period	NO_x 5-year Average Emission Rate (lb/hr)	NO_x 5-year Average Process Rate (tons/hr RLS)	NO_x 5-year Average Emission Factor (lb/ton RLS)
Recovery Boiler (EU 006)																		
											245.0 [e]	--	--		2004, 2005	513.2	32.8	15.67
11/2/1999	23.08	--	23.08	32.46	0.71	1999	1999-2004	23.75	33.30	0.71	--	--	--	1999	2004, 2005	513.2	32.8	15.67
11/1/2000 [f]	52.54	--	52.54	24.19	2.17	2000	1999-2004	23.75	33.30	0.71	--	--	--	2000	2004, 2005	513.2	32.8	15.67
12/7/2001	20.97	0.017	20.97	34.88	0.60	2001	1999-2004	23.75	33.30	0.71	--	--	--	2001	2004, 2005	513.2	32.8	15.67
9/16/2002	24.99	0.034	24.99	32.44	0.77	2002	1999-2004	23.75	33.30	0.71	--	--	--	2002	2004, 2005	513.2	32.8	15.67
2/10/2003	26.05	0.021	26.05	33.23	0.78	2003	1999-2004	23.75	33.30	0.71	--	--	--	2003	2004, 2005	513.2	32.8	15.67
5/24-25/2004	23.68	0.018	23.68	33.50	0.71	2004	1999-2004	23.75	33.30	0.71	525.0	33.50	15.67	2004	2004, 2005	513.2	32.8	15.67
6/8/2005	21.86	0.017	21.86	32.02	0.68	2005	2001-2005	23.51	33.21	0.71	501.4	32.02	15.66	2005	2004, 2005	513.2	32.8	15.67
5/24/2006	24.87	0.019	24.87	31.49	0.79	2006	2002-2006	24.29	32.54	0.75	--	--	--	2006	2004, 2005	513.2	32.8	15.67
3/28/2007	20.61	0.023	20.61	34.23	0.60	2007	2003-2007	23.41	32.89	0.71	--	--	--	2007	2004, 2005	513.2	32.8	15.67
5/14/2008	25.32	0.020	25.32	34.82	0.73	2008	2004-2008	23.27	33.21	0.70	--	--	--	2008	2004, 2005	513.2	32.8	15.67

Test Date	Methanol Emission Rate (lb/hr)	Methanol Process Rate (ton RLS/hr)	Methanol Emission Factor (lb/ton RLS)	5-year Average Reporting Year	5-year Average Averaging Period	5-year Average Emission Rate (lb/hr)	5-year Average Process Rate (tons/hr RLS)	5-year Average Emission Factor (lb/ton RLS)
1999	--	--	--	1999	2003-2007	--	--	0.33
2000	--	--	--	2000	2003-2007	--	--	0.33
2001	--	--	--	2001	2003-2007	--	--	0.33
2002	--	--	--	2002	2003-2007	--	--	0.33
10/23/2003	6.33	--	--	2003	2003-2007	10.98	33.29	0.33
07/27-29/2004	23.98	--	--	2004	2003-2007	10.98	33.29	0.33
6/6/2005	11.43	--	--	2005	2003-2007	10.98	33.29	0.33
5/22/2006	5.60	--	--	2006	2003-2007	10.98	33.29	0.33
3/27/2007	7.53	32.77	0.23	2007	2003-2007	10.98	33.29	0.33
5/12/2008	3.37	33.82	0.10	2008	2004-2008	10.38	33.29	0.31

Continuous Monitor Data

Reporting Year	CO Emission Rate [d] (lb/ton RLS)	5-year Average Reporting Year	5-year Average Averaging Period	5-year Average Emission Rate lb/ton RLS	SO_2 Emission Rate [g] (lb/ton RLS)
1999	3.48	1999	1999-2003	3.35	8.71
2000	3.70	2000	1999-2003	3.35	8.61
2001	3.61	2001	1999-2003	3.35	7.14
2002	3.70	2002	1999-2003	3.35	9.07
2003	2.24	2003	1999-2003	3.35	7.16
2004	3.40	2004	2000-2004	3.33	6.54
2005	5.55	2005	2001-2005	3.70	6.09
2006	8.82	2006	2002-2006	4.74	6.10
2007	5.17	2007	2003-2007	5.04	4.04
2008	7.57	2008	2004-2008	6.10	5.89

Notes:
RLS = Red liquor solids
ADUP = air-dried unbleached pulp

[a] Maximum permitted PM emission rate, as required by 40 CFR 63 Subpart MM, is 0.040 gr/dscf @ 8% O_2 after March 13, 2004.
Actual PM emission rates above 0.040 gr/dscf @ 8% O_2 are to be corrected to 0.040 gr/dscf. However, no measured grain loading exceeded this limit.
[b] Emission factor in lb/ton RLS has been calculated using the corrected lb/hr PM emission rate.
[c] 5-year averages based on corrected lb/hr PM emission rate.
[d] Based on continuous monitor and process data as reported in AORs. CO process monitor is NOT a certified CEMS unit.
[e] Average emission rate from stack testing conducted 1995. Not considered representative of current operations.
[f] Not representative of typical operation. Therefore data has not been included in average calculations.
[g] Based on SO_2 CEMS and process data as reported in AORs.

TABLE A-2
ACTUAL OPERATING CONDITIONS FOR THE RECOVERY BOILER (1999 - 2008)
RAYONIER PERFORMANCE FIBERS, FERNANDINA BEACH, FLORIDA

										Heat Input		
	Operating Hours	ADUP	Net Pulp	Net Pulp	RLS	Ratio		No. 6 Fuel Oil	No. 6 Fuel Oil	RLS	No. 6 Fuel Oil	Total Heat Input
Year	(hours/yr)	(TPY)	(ADMT/yr)	(TPY)	(TPY)	ADUP/ADMT	ton RLS/ADUP	(10^3 gal/yr)	(% Sulfur)	(MMBtu/yr)	(MMBtu/yr)	(MMBtu/yr)
Recovery Boiler (EU 006)												
1999	6,578	171,141	119,688	131,933	204,939	1.430	1.197	3,241.0	2.3	3,824,162	489,391	4,313,553
2000	8,423	214,703	151,515	167,016	232,105	1.417	1.081	3,772.2	2.3	4,331,079	569,602	4,900,682
2001	8,177	223,669	146,247	161,210	226,950	1.529	1.015	3,267.0	2.4	4,234,887	493,317	4,728,204
2002	7,970	217,383	145,895	160,822	232,525	1.490	1.070	3,086.0	--	4,338,917	465,986	4,804,903
2003	7,871	223,692	144,982	159,815	242,230	1.543	1.083	2,041.0	1.6	4,520,012	308,191	4,828,203
2004	8,072	223,276	145,892	160,818	241,500	1.530	1.082	2,116.0	1.5	4,506,390	319,516	4,825,906
2005	8,205	232,748	151,354	166,839	251,575	1.538	1.081	1,830.0	1.6	4,694,390	276,330	4,970,720
2006	8,044	225,002	146,880	161,907	241,080	1.532	1.071	1,719.2	1.6	4,498,553	259,599	4,758,152
2007	7,821	225,987	146,821	161,842	240,900	1.539	1.066	878.0	1.8	4,495,194	132,578	4,627,772
2008	7,609	225,114	147,969	163,108	245,220	1.521	1.089	1,090.3	1.6	4,575,805	164,641	4,740,446
Maximum:	8,423	232,748	151,515	167,016	251,575	1.543	1.197	3,772.2	2.4	4,694,390	569,602	4,970,720
Average:	7,877	218,272	144,724	159,531	235,902	1.507	1.084	2,304.1	1.9	4,401,939	347,915	4,749,854
Minimum:	6,578	171,141	119,688	131,933	204,939	1.417	1.015	878.0	1.5	3,824,162	132,578	4,313,553

Notes:
RLS = Red liquor solids.
ADUP = air-dried unbleached pulp.
ADMT = Air dried metric tonnes (2,204.62 lbs).
TPY = Ton (2,000 lbs) per year.

TABLE A-3

REVISED EMISSION FACTORS USED TO DETERMINE ACTUAL ANNUAL EMISSIONS (1999-2008) FOR THE RECOVERY BOILER

RAYONIER PERFORMANCE FIBERS, FERNANDINA BEACH, FLORIDA

Source Description	EU ID	Annual Operation (hr/yr)	Annual Fuel Usage	Factor Units	Pollutant Emission Factors										
					SO_2	NO_x	CO	PM	PM_{10}	$PM_{2.5}$	VOC	SAM	Lead	Mercury	Fluoride
<u>Recovery Boiler</u>	006														
1999 Actual Emission Factors															
- *RLS*		6,578	204,939 ton RLS	lb/ton RLS	8.71 [D]	15.67 [L]	3.35 [K]	0.71 [B]	0.64 [A]	0.52 [A]	0.07 [N]	0.38 [J]	9.6E-05 [I]	4.7E-06 [I]	--
- *Residual Oil - 2.25% Sulfur*			3,241 x10^3 gal	lb/10^3 gal	36.03 [M]	47.0 [E]	5 [E]	2.44 [E]	2.44 [F]	2.36 [F]	0.25 [G]	1.59 [J]	1.5E-03 [H]	1.1E-04 [H]	3.7E-02 [H]
2000 Actual Emission Factors															
- *RLS*		8,423	232,105 ton RLS	lb/ton RLS	8.61 [D]	15.67 [L]	3.35 [K]	0.71 [B]	0.64 [A]	0.52 [A]	0.07 [N]	0.38 [J]	9.6E-05 [I]	4.7E-06 [I]	--
- *Residual Oil - 2.25% Sulfur*			3,772 x10^3 gal	lb/10^3 gal	36.15 [M]	47.0 [E]	5 [E]	2.44 [E]	2.44 [F]	2.36 [F]	0.25 [G]	1.59 [J]	1.5E-03 [H]	1.1E-04 [H]	3.7E-02 [H]
2001 Actual Emission Factors															
- *RLS*		8,177	226,950 ton RLS	lb/ton RLS	7.14 [D]	15.67 [L]	3.35 [K]	0.71 [B]	0.64 [A]	0.52 [A]	0.07 [N]	0.31 [J]	9.6E-05 [I]	4.7E-06 [I]	--
- *Residual Oil - 2.42% Sulfur*			3,267 x10^3 gal	lb/10^3 gal	7.74 [M]	47.0 [E]	5 [E]	2.53 [E]	2.53 [F]	2.45 [F]	0.25 [G]	0.34 [J]	1.5E-03 [H]	1.1E-04 [H]	3.7E-02 [H]
2002 Actual Emission Factors															
- *RLS*		7,970	232,525 ton RLS	lb/ton RLS	9.07 [D]	15.67 [L]	3.35 [K]	0.71 [B]	0.64 [A]	0.52 [A]	0.07 [N]	0.40 [J]	9.6E-05 [I]	4.7E-06 [I]	--
- *Residual Oil - 2.4% Sulfur*			3,086 x10^3 gal	lb/10^3 gal	7.68 [M]	47.0 [E]	5 [E]	2.53 [E]	2.53 [F]	2.45 [F]	0.25 [G]	0.34 [J]	1.5E-03 [H]	1.1E-04 [H]	3.7E-02 [H]
2003 Actual Emission Factors															
- *RLS*		7,871	242,230 ton RLS	lb/ton RLS	7.16 [D]	15.67 [L]	3.35 [K]	0.71 [B]	0.64 [A]	0.52 [A]	0.07 [N]	0.32 [J]	9.6E-05 [I]	4.7E-06 [I]	--
- *Residual Oil - 1.6% Sulfur*			2,041 x10^3 gal	lb/10^3 gal	5.12 [M]	47.0 [E]	5 [E]	1.79 [E]	1.79 [F]	1.74 [F]	0.25 [G]	0.23 [J]	1.5E-03 [H]	1.1E-04 [H]	3.7E-02 [H]
2004 Actual Emission Factors															
- *RLS*		8,072	241,500 ton RLS	lb/ton RLS	6.54 [D]	15.67 [L]	3.33 [K]	0.71 [B]	0.64 [A]	0.52 [A]	0.07 [N]	0.29 [J]	9.6E-05 [I]	4.7E-06 [I]	--
- *Residual Oil - 1.5% Sulfur*			2,116 x10^3 gal	lb/10^3 gal	4.80 [M]	47.0 [E]	5 [E]	1.70 [E]	1.70 [F]	1.65 [F]	0.25 [G]	0.21 [J]	1.5E-03 [H]	1.1E-04 [H]	3.7E-02 [H]
2005 Actual Emission Factors															
- *RLS*		8,205	251,575 ton RLS	lb/ton RLS	6.09 [D]	15.67 [L]	3.70 [K]	0.71 [B]	0.64 [A]	0.52 [A]	0.07 [N]	0.27 [J]	9.6E-05 [I]	4.7E-06 [I]	--
- *Residual Oil - 1.6% Sulfur*			1,830 x10^3 gal	lb/10^3 gal	5.12 [M]	47.0 [E]	5 [E]	1.79 [E]	1.79 [F]	1.74 [F]	0.25 [G]	0.23 [J]	1.5E-03 [H]	1.1E-04 [H]	3.7E-02 [H]
2006 Actual Emission Factors															
- *RLS*		8,044	241,080 ton RLS	lb/ton RLS	6.10 [D]	15.67 [L]	4.74 [K]	0.75 [B]	0.68 [A]	0.55 [A]	0.07 [N]	0.27 [J]	9.6E-05 [I]	4.7E-06 [I]	--
- *Residual Oil - 1.6% Sulfur*			1,719 x10^3 gal	lb/10^3 gal	5.12 [M]	47.0 [E]	5 [E]	1.79 [E]	1.79 [F]	1.74 [F]	0.25 [G]	0.23 [J]	1.5E-03 [H]	1.1E-04 [H]	3.7E-02 [H]
2007 Actual Emission Factors															
- *RLS*		7,821	240,900 ton RLS	lb/ton RLS	4.04 [D]	15.67 [L]	5.04 [K]	0.71 [B]	0.65 [A]	0.53 [A]	0.07 [N]	0.18 [J]	9.6E-05 [I]	4.7E-06 [I]	--
- *Residual Oil - 1.8% Sulfur*			878 x10^3 gal	lb/10^3 gal	5.76 [M]	47.0 [E]	5 [E]	1.98 [E]	1.98 [F]	1.92 [F]	0.25 [G]	0.25 [J]	1.5E-03 [H]	1.1E-04 [H]	3.7E-02 [H]
2008 Actual Emission Factors															
- *RLS*		7,609	245,220 ton RLS	lb/ton RLS	5.89 [D]	15.67 [L]	6.10 [K]	0.70 [B]	0.64 [A]	0.52 [A]	0.06 [N]	0.26 [J]	9.6E-05 [I]	4.7E-06 [I]	--
- *Residual Oil - 1.6% Sulfur*			1,090 x10^3 gal	lb/10^3 gal	6.32 [M]	47.0 [E]	5 [E]	1.79 [E]	1.79 [F]	1.74 [F]	0.25 [G]	0.28 [J]	1.5E-03 [H]	1.1E-04 [H]	3.7E-02 [H]

<u>Notes:</u>

RLS = Red liquor solids

ADUP = air-dried unbleached pulp

[A] NCASI Technical Bulletin No. 884, Table 5.3 (Sulfite Recovery Furnaces, median values). 90.7% of PM is PM_{10}, 73.7% of PM is $PM_{2.5}$.

[B] Based on 5-year average stack tests (see Table A-2).

[C] NCASI Technical Bulletin No. 858, Table 15A (DCE Recovery Furnaces, median values).

[D] Based on continuous monitor data as reported in AORs.

[E] AP-42, Table 1.3-1. Sulfur content reported in the AOR and assuming scrubber efficiency of 90% for PM and 98% for SO_2.

[F] AP-42, Table 1.3-4 for combustion of No. 6 fuel oil with scrubber control. 100% of PM emissions are PM_{10}, 97% of PM emissions are $PM_{2.5}$.

[G] AP-42, Table 1.3-3.

[H] AP-42, Table 1.3-11. Based on uncontrolled emissions.

[I] NCASI Technical Bulletin No. 858, Table 15B (Sulfite Recovery Furnaces, median values).

[J] Based on similar derivation of sulfuric acid mist from AP-42 for fuel oil: 3.6% of SO_2 becomes SO_3 then take into account the ratio of sulfuric acid mist and sulfur trioxide molecular weights (98/80).

[K] Based on 5-year average continuous monitor data as reported in AORs.

[L] Based on average of stack testing conducted in 2004 and 2005.

[M] Based on stoichiometric conversion of fuel sulfur to SO_2 and the calculated scrubber efficiency.
Scrubber efficiency calculation based SO_2 scrubber input (RLS and fuel oil sulfur content) and SO_2 emissions from scrubber (CEMS monitor).

[N] Based on 5-year average of stack tests (see Table A-2) for methanol and a ratio of total hydrocarbon to methanol emissions of 0.21.
Ratio calculated from data contained in NCASI Technical Bulletin No. 858. THC emission rate for ammonia-based sulfite recovery boilers using EPA Method 25A.

TABLE A-4
BASELINE ACTUAL ANNUAL (1999-2008) EMISSIONS FOR THE RECOVERY BOILER
RAYONIER PERFORMANCE FIBERS, FERNANDINA BEACH, FLORIDA

Source Description	EU ID	Pollutant Emission Rate (TPY)										
		SO_2	NO_x	CO	PM	PM_{10}	$PM_{2.5}$	VOC	SAM	Lead	Mercury	Fluoride
Recovery Boiler	006											
1999 Actual Emissions												
- RLS		892.05	1,605.26	343.61	72.65	65.89	53.54	6.97	39.25	9.84E-03	4.82E-04	--
- Residual Oil		58.39	76.16	8.10	3.95	3.95	3.83	0.11	2.57	2.45E-03	1.83E-04	6.04E-02
- Total		*950.44*	*1,681.42*	*351.71*	*76.60*	*69.84*	*57.37*	*7.08*	*41.82*	*1.23E-02*	*6.65E-04*	*6.04E-02*
2000 Actual Emissions												
- RLS		999.04	1,818.05	389.16	82.28	74.63	60.64	7.89	43.96	1.11E-02	5.45E-04	--
- Residual Oil		68.19	88.65	9.43	4.59	4.59	4.46	0.13	3.00	2.85E-03	2.13E-04	7.04E-02
- Total		*1,067.23*	*1,906.69*	*398.59*	*86.87*	*79.22*	*65.10*	*8.02*	*46.96*	*1.40E-02*	*7.59E-04*	*7.04E-02*
2001 Actual Emissions												
- RLS		810.42	1,777.67	380.51	80.45	72.97	59.29	7.71	35.66	1.09E-02	5.33E-04	--
- Residual Oil		18.78	76.77	8.17	4.13	4.13	4.00	0.11	0.56	2.47E-03	1.85E-04	6.09E-02
- Total		*829.20*	*1,854.44*	*388.68*	*84.58*	*77.10*	*63.30*	*7.83*	*36.22*	*1.34E-02*	*7.18E-04*	*6.09E-02*
2002 Actual Emissions												
- RLS		1,054.27	1,821.34	389.86	82.43	74.76	60.75	7.90	46.39	1.12E-02	5.46E-04	--
- Residual Oil		11.85	72.52	7.72	3.90	3.90	3.78	0.10	0.52	2.33E-03	1.74E-04	5.76E-02
- Total		*1,066.12*	*1,893.86*	*397.58*	*86.33*	*78.66*	*64.53*	*8.01*	*46.91*	*1.35E-02*	*7.21E-04*	*5.76E-02*
2003 Actual Emissions												
- RLS		867.60	1,897.35	406.13	85.87	77.88	63.29	8.23	38.17	1.16E-02	5.69E-04	--
- Residual Oil		8.01	47.96	5.10	1.83	1.83	1.77	0.07	0.23	1.54E-03	1.15E-04	3.81E-02
- Total		*875.61*	*1,945.32*	*411.24*	*87.70*	*79.71*	*65.06*	*8.30*	*38.40*	*1.32E-02*	*6.85E-04*	*3.81E-02*
2004 Actual Emissions												
- RLS		789.75	1,891.64	401.90	85.61	77.65	63.10	8.21	34.75	1.16E-02	5.68E-04	--
- Residual Oil		6.91	49.73	5.29	1.80	1.80	1.75	0.07	0.22	1.60E-03	1.20E-04	3.95E-02
- Total		*796.66*	*1,941.36*	*407.19*	*87.41*	*79.45*	*64.84*	*8.28*	*34.97*	*1.32E-02*	*6.87E-04*	*3.95E-02*
2005 Actual Emissions												
- RLS		765.96	1,970.55	465.34	89.18	80.89	65.73	8.55	33.70	1.21E-02	5.91E-04	--
- Residual Oil		5.82	43.01	4.58	1.64	1.64	1.59	0.06	0.21	1.38E-03	1.03E-04	3.41E-02
- Total		*771.78*	*2,013.56*	*469.92*	*90.82*	*82.53*	*67.32*	*8.61*	*33.91*	*1.35E-02*	*6.95E-04*	*3.41E-02*
2006 Actual Emissions												
- RLS		735.34	1,888.35	571.55	90.01	81.64	66.34	8.20	32.36	1.16E-02	5.67E-04	--
- Residual Oil		7.73	40.40	4.30	1.54	1.54	1.49	0.06	0.19	1.30E-03	9.71E-05	3.21E-02
- Total		*743.07*	*1,928.75*	*575.85*	*91.55*	*83.18*	*67.83*	*8.25*	*32.55*	*1.29E-02*	*6.64E-04*	*3.21E-02*
2007 Actual Emissions												
- RLS		486.40	1,886.94	606.75	85.89	77.91	63.30	8.19	21.40	1.16E-02	5.66E-04	--
- Residual Oil		2.10	20.63	2.20	0.87	0.87	0.84	0.03	0.11	6.63E-04	4.96E-05	1.64E-02
- Total		*488.50*	*1,907.57*	*608.95*	*86.76*	*78.77*	*64.15*	*8.22*	*21.51*	*1.22E-02*	*6.16E-04*	*1.64E-02*
2008 Actual Emissions												
- RLS		722.34	1,920.77	748.27	86.05	78.04	63.42	7.89	31.78	1.18E-02	5.76E-04	--
- Residual Oil		3.45	25.62	2.73	0.98	0.98	0.95	0.04	0.15	8.23E-04	6.16E-05	2.03E-02
- Total		*725.79*	*1,946.40*	*751.00*	*87.02*	*79.02*	*64.36*	*7.92*	*31.93*	*1.26E-02*	*6.38E-04*	*2.03E-02*

TABLE A-5
SUMMARY OF BASELINE 2-YEAR AVERAGE ACTUAL (1999-2008) EMISSIONS
RAYONIER PERFORMANCE FIBERS, FERNANDINA BEACH

Source Description	EU ID	Pollutant Emission Rate (TPY) SO_2	NO_x	CO	PM	PM_{10}	$PM_{2.5}$	VOC	SAM	Lead	Mercury	Fluoride
1999 - 2000 Average Emissions												
- Recovery Boiler	*006*	1,008.84	1,794.06	375.15	81.74	74.53	61.23	7.55	44.39	1.31E-02	7.12E-04	0.065
- Total		***1,008.84***	***1,794.06***	***375.15***	***81.74***	***74.53***	***61.23***	***7.55***	***44.39***	***1.31E-02***	***7.12E-04***	***0.065***
2000 - 2001 Average Emissions												
- Recovery Boiler	*006*	948.22	1,880.57	393.64	85.73	78.16	64.20	7.92	41.59	1.37E-02	7.38E-04	0.066
- Total		***948.22***	***1,880.57***	***393.64***	***85.73***	***78.16***	***64.20***	***7.92***	***41.59***	***1.37E-02***	***7.38E-04***	***0.066***
2001 - 2002 Average Emissions												
- Recovery Boiler	*006*	947.66	1,874.15	393.13	85.46	77.88	63.92	7.92	41.56	1.34E-02	7.19E-04	0.059
- Total		***947.66***	***1,874.15***	***393.13***	***85.46***	***77.88***	***63.92***	***7.92***	***41.56***	***1.34E-02***	***7.19E-04***	***0.059***
2002 - 2003 Average Emissions												
- Recovery Boiler	*006*	970.87	1,919.59	404.41	87.01	79.19	64.80	8.16	42.66	1.33E-02	7.03E-04	0.048
- Total		***970.87***	***1,919.59***	***404.41***	***87.01***	***79.19***	***64.80***	***8.16***	***42.66***	***1.33E-02***	***7.03E-04***	***0.048***
2003 - 2004 Average Emissions												
- Recovery Boiler	*006*	836.14	1,943.34	409.22	87.55	79.58	64.95	8.29	36.69	1.32E-02	6.86E-04	0.039
- Total		***836.14***	***1,943.34***	***409.22***	***87.55***	***79.58***	***64.95***	***8.29***	***36.69***	***1.32E-02***	***6.86E-04***	***0.039***
2004 - 2005 Average Emissions												
- Recovery Boiler	*006*	784.22	1,977.46	438.56	89.12	80.99	66.08	8.45	34.44	1.33E-02	6.91E-04	0.037
- Total		***784.22***	***1,977.46***	***438.56***	***89.12***	***80.99***	***66.08***	***8.45***	***34.44***	***1.33E-02***	***6.91E-04***	***0.037***
2005 - 2006 Average Emissions												
- Recovery Boiler	*006*	757.43	1,971.15	522.88	91.19	82.85	67.57	8.43	33.23	1.32E-02	6.79E-04	0.033
- Total		***757.43***	***1,971.15***	***522.88***	***91.19***	***82.85***	***67.57***	***8.43***	***33.23***	***1.32E-02***	***6.79E-04***	***0.033***
2006 - 2007 Average Emissions												
- Recovery Boiler	*006*	615.79	1,918.16	592.40	89.16	80.98	65.99	8.24	27.03	1.25E-02	6.40E-04	0.024
- Total		***615.79***	***1,918.16***	***592.40***	***89.16***	***80.98***	***65.99***	***8.24***	***27.03***	***1.25E-02***	***6.40E-04***	***0.024***
2007 - 2008 Average Emissions												
- Recovery Boiler	*006*	607.15	1,926.98	679.97	86.89	78.90	64.25	8.07	26.72	1.24E-02	6.27E-04	0.018
- Total		***607.15***	***1,926.98***	***679.97***	***86.89***	***78.90***	***64.25***	***8.07***	***26.72***	***1.24E-02***	***6.27E-04***	***0.018***
		'99 - '00	'04 - '05	'07 - '08	'05 - '06	'05 - '06	'05 - '06	'04 - '05	'99 - '00	'00 - '01	'00 - '01	'00 - '01
Highest Consecutive 2-Year Average		1,008.84	1,977.46	679.97	91.19	82.85	67.57	8.45	44.39	1.37E-02	7.38E-04	0.066

APPENDIX B

AOR DATA FOR 1999-2008 FOR THE RECOVERY BOILER

TABLE B-1
ACTUAL ANNUAL (1999-2008) EMISSIONS FROM ANNUAL OPERATING REPORTS FOR THE RECOVERY BOILER
RAYONIER PERFORMANCE FIBERS, FERNANDINA BEACH, FLORIDA

Source Description	EU ID	Annual Operation (hr/yr)	Annual Fuel Usage	Units	Pollutant Emission Factors										
					SO_2	NO_x	CO	PM	PM_{10}	$PM_{2.5}$	VOC	SAM	Lead	Mercury	Fluoride
Recovery Boiler	006														
1999 Actual Emission Factors		6,578	171,141 ton ADUP	TPY	892.1 [a]	805.9 [c]	356.4 [a]	119.4 [d]	103.7 [e]	--	299.50 [f]	--	--	--	--
			3,241 x10^3 gal	TPY	58.4 [b]	76.2 [b]	8.1 [b]	3.9 [b]	3.4 [b]	--	0.45 [b]	--	--	--	--
2000 Actual Emission Factors		8,423	214,703 ton ADUP	TPY	999.0 [a]	1,031.8 [c]	429.3 [a]	194.1 [d]	168.5 [e]	--	375.73 [f]	--	--	--	--
			3,772 x10^3 gal	TPY	68.2 [b]	88.6 [b]	9.4 [b]	4.52 [b]	3.92 [b]	--	0.53 [b]	--	0.07 [b]	--	--
2001 Actual Emission Factors		8,177	223,669 ton ADUP	TPY	810.4 [a]	924.9 [c]	409.4 [a]	212.3 [d]	189.5 [e]	--	391.42 [f]	--	--	--	--
			3,267 x10^3 gal	TPY	18.8 [b]	76.8 [b]	8.2 [b]	4.15 [b]	3.60 [b]	--	1.24 [b]	--	0.07 [b]	--	--
2002 Actual Emission Factors		7,970	217,383 ton ADUP	TPY	1,054.3 [a]	903.8 [c]	429.7 [a]	77.22 [d]	68.95 [e]	--	380.42 [f]	--	--	--	--
			3,086 x10^3 gal	TPY	20.4 [b]	72.5 [b]	7.7 [b]	3.59 [b]	3.12 [b]	--	1.17 [b]	--	0.06 [b]	--	--
2003 Actual Emission Factors		7,871	223,692 ton ADUP	TPY	867.6 [a]	916.3 [c]	271.1 [a]	48.00 [d]	42.85 [e]	--	391.46 [f]	--	--	--	--
			2,041 x10^3 gal	TPY	8.0 [b]	48.0 [b]	5.1 [b]	1.87 [b]	1.62 [b]	--	0.78 [b]	--	0.06 [b]	--	--
2004 Actual Emission Factors		8,072	223,276 ton ADUP	TPY	789.8 [a]	2,070.5 [h]	410.6 [a]	84.11 [d]	75.10 [e]	--	28.40 [i]	--	--	--	--
			2,116 x10^3 gal	TPY	6.9 [b]	49.7 [b]	5.3 [b]	1.80 [b]	1.55 [b]	--	0.8 [b]	--	0.06 [b]	--	--
2005 Actual Emission Factors		8,205	232,748 ton ADUP	TPY	766.0 [a]	2,014.1 [j]	698.7 [a]	85.86 [d]	76.66 [e]	--	57.68 [i]	--	--	--	--
			1,830 x10^3 gal	TPY	5.8 [b]	43.0 [b]	4.6 [b]	1.6	1.4 [b]	--	0.70 [b]	--	0.07 [b]	--	--
2006 Actual Emission Factors		8,044	225,002 ton ADUP	TPY	735.3 [a]	1,976.1 [j]	1,063.0 [a]	95.26 [d]	85.05 [e]	--	22.86 [i]	--	--	--	--
			1,719 x10^3 gal	TPY	7.7 [b]	40.4 [b]	4.3 [b]	2.02 [b]	1.75 [b]	--	0.65 [b]	--	0.06 [b]	--	--
2007 Actual Emission Factors		7,821	225,987 ton ADUP	TPY	486.4 [a]	1,940.1 [j]	623.3 [a]	72.50 [d]	64.76 [e]	--	22.99 [i]	--	--	--	--
			878 x10^3 gal	TPY	2.1 [b]	20.6 [b]	2.2 [b]	0.86 [b]	0.74 [b]	--	0.33 [b]	--	0.06 [b]	--	--
2008 Actual Emission Factors		7,609	225,114 ton ADUP	TPY	722.3 [a]	1,882.0 [j]	927.6 [a]	89.21 [d]	79.65 [e]	68.50	22.96 [3B]	--	--	--	--
			1,090 x10^3 gal	TPY	3.5 [b]	25.6 [b]	2.7 [b]	0.98 [b]	0.85 [b]	0.6 [b]	0.41 [b]	--	0.06 [b]	--	--

Notes:
RLS = Red liquor solids
ADUP = air-dried unbleached pulp

[a] Based on continuous monitor data.
[b] AP-42, Section 1.3.
[c] Based on NOx stack testing conducted in 1995.
[d] Based on annual compliance test.
[e] Assuming PM10 is 89% of PM.
[f] Based on 3.5 lb/ton ADUP.
[g] Based on performance test data.
[h] Based on NOx stack testing conducted in 2004.
[i] Based on methanol stack testing and a MeOH/VOC ratio of 0.95.
[j] Based on NOx stack testing conducted in 2005.
[k] Based on stoichiometric conversion of fuel sulfur to SO_2 and the calculated scrubber efficiency.
Scrubber efficiency calculation based SO_2 scrubber input (RLS and fuel oil sulfur content) and SO_2 emissions from scrubber (process monitor).