Memorandum

Florida Department of Environmental Protection

TO: Mike Cooke, Division of Air Resource Management

THRU: Trina Vielhauer, Bureau of Air Regulation
Jeff Koerner, BAR - Air Permitting North

FROM: Bruce Mitchell, BAR - Air Permitting North

DATE: February 20, 2006

SUBJECT: Rayonier Performance Fibers LLC
Fernandina Beach Mill
Final Air Construction Permit
Permit Project No. 0890004-018-AC

Attached is the final air construction permit for the Rayonier Performance Fibers LLC's existing Fernandina Beach Mill, which is located at The Foot of Gum Street in Fernandina Beach, Nassau County, Florida. The permit authorizes the replacement of three existing oil-fired power boilers (Nos. 1- 3) with a new wood-fired power boiler (No. 6). The new boiler is actually an existing pulverized coal-fired boiler that will be converted to a fluidized-bed boiler. Emissions will be controlled by staged combustion (NOx), an electrostatic precipitator (PM), and a wet alkaline scrubber (acid gases). The permit requires continuous emissions monitoring systems for opacity, CO, NOx, and SO_2 emissions.

The permit also authorizes an initial increase of the facility's production from 153,205 to 162,000 air dried metric ton (ADMT) per consecutive 12-months, rolling total. After successful installation of a new blow heat recovery system to control VOC emissions from all hot caustic extract (HCE) cells, the permit authorizes a final production increase to 175,000 ADMT per consecutive 12-months, rolling total. In order to achieve the increases in production, the permittee will also be authorized to perform the following construction and work: add a new HCE washer press roll; begin first improvements to pulp machine (drying and head-box); add a new HCE evaporator train; install a new HCE blow heat recovery system to control all HCE cells; add a new HCE cell; install a new HCE washer; begin second improvements to pulp machine (drying and speed increase); and install a new post-HCE washer. The combined projects avoid PSD preconstruction review based on the netting analysis that includes the shutdown boilers.

We issued a draft permit package on January 26, 2006. The public notice was published in The News Leader on February 1, 2006. Comments were received from the applicant; however, no changes were made to the final permit other than corrections of typographical errors. "Day 90" is May 13, 2006. I recommend approval of the final air construction permit.

Attachments

MGC/tv/jk/bm

Mitchell, Bruce

From: Crandall, Lea
Sent: Friday, February 17, 2006 2:44 PM
To: Gibson, Victoria; Koerner, Jeff
Cc: Mitchell, Bruce
Subject: RE: Rayonier

Good Afternoon,

Nothing filed.

Thanks,
Lea

Lea Crandall
Agency Clerk
Department of Environmental Protection
3900 Commonwealth Boulevard, MS 35
Tallahassee, FL 32399-3000
Phone: (850) 245-2212 SC: 205-2212
Fax: (850) 245-2303

-----Original Message-----
From: Gibson, Victoria
Sent: Friday, February 17, 2006 2:34 PM
To: Koerner, Jeff
Cc: Crandall, Lea; Mitchell, Bruce
Subject: RE: Rayonier

Jeff and Bruce,

I don't see anything at the moment.....I will forward your request over to Lea and see if anything has come in today.

Vickie

From: Koerner, Jeff
Sent: Friday, February 17, 2006 2:24 PM
To: Mitchell, Bruce
Cc: Gibson, Victoria
Subject: Rayonier

Bruce,

Check with Vickie to see if OGC received any petitions for:

Draft Air Construction Permit No. 0890004-018-AC
New Power Boiler No. 6 and Digester No. 6 Project

She keeps a list of these filings. May need to call OGC to make sure.

Thanks!

Jeff Koerner, BAR - Air Permitting North
Florida Department of Environmental Protection
850/921-9536

FINAL DETERMINATION

Rayonier Performance Fibers LLC
Fernandina Beach Mill
Facility ID No. 0890004
Nassau County, Florida

Air Construction Permit
Permit Project No. 0890004-018-AC

I. Public Notice.

On January 26, 2006, the Department issued an "INTENT TO ISSUE AN AIR CONSTRUCTION PERMIT" to Rayonier Performance Fibers LLC for their existing Fernandina Beach Mill located at The Foot of Gum Street in Fernandina Beach, Nassau County, Florida. The "PUBLIC NOTICE OF INTENT TO ISSUE AN AIR CONSTRUCTION PERMIT" was published in the NEWS LEADER on February 1, 2006. The Draft Permit was available for public inspection at the Department's Northeast District office in Jacksonville and the Bureau of Air Regulation's office in Tallahassee. Proof of publication of the "PUBLIC NOTICE OF INTENT TO ISSUE AN AIR CONSTRUCTION PERMIT" was received on February 3, 2006.

II. Public Comments.

Comments from the applicant were received on February 14, 2006. No other comments were received during the public comment period. The applicant's comments and the Department's response are summarized below.

1. Request: The applicant requests that the expiration date be set with sufficient time to submit an application for a revised Title V Air Operation permit to be submitted 180 days prior to expiration. Response: Based on the schedule provided and discussion with the applicant, the expiration date was established as March 1, 2009. The due date for the Title V Air Operation Permit Application was established as March 24, 2008. See Facility-wide condition No. 14.

2. Request: The applicant notes that the draft permit establishes emissions caps for CO, NO_x, and SO_2 emissions from power boiler No. 6. Compliance with the emissions caps is demonstrated by continuous emissions monitors and must include all valid data (including startups, shutdowns, and malfunctions). The applicant requests that these permit conditions include the following phrase, "... to the extent such CEMS data exceed startup, shutdown, and malfunction emissions in the baseline." After further discussion, the applicant indicates that additional testing of the existing power boilers may be performed to better determine emissions during startup and shutdown. Therefore, the applicant may request a revision of one or more of the emissions caps based on this information. Response: The Department acknowledges that the emissions caps were based on the data provided in the application, which the applicant identified as the best available information at this time. Should better emissions data become available, the applicant may request a modification of this permit. The Department would process this request as it would any application. If approved, such a request would require a public notice and comment period. No changes were made to the final permit as a result of the applicant's comments.

III. Conclusion.

The permitting authority hereby issues the final air construction Permit No. 0890004-018-AC with the minor changes noted above.

Department of Environmental Protection

Jeb Bush
Governor

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

Colleen M. Castille
Secretary

NOTICE OF FINAL AIR CONSTRUCTION PERMIT

In the Matter of an
Application for Permit by:

Mr. Fred J. Perrett
General Manager and Responsible Official
Rayonier Performance Fibers LLC
Fernandina Beach Mill
The Foot of Gum Street
P.O. Box 2002
Fernandina Beach, Florida 32035-1309

Air Permit No. 0890004-018-AC
Power Boiler No. 6 and
Production Increase
Fernandina Beach Mill
Nassau County, Florida

Enclosed is final air construction Permit No. 0890004-018-AC for the requested facility modifications to Rayonier Performance Fibers LLC's existing sulfite mill, which located at The Foot of Gum Street in Fernandina Beach, Nassau County, Florida. The permit authorizes the replacement of three existing oil-fired power boilers (Nos. 1- 3) with a wood-fired, fluidized bed power boiler (No. 6). The permit also authorizes an initial increase of the facility's production from 153,205 to 162,000 air dried metric ton (ADMT) per consecutive 12-months, rolling total. After successful installation of a new blow heat recovery system to control VOC (volatile organic compounds) emissions from all hot caustic extract (HCE) cells, the permit authorizes a final production increase to 175,000 ADMT per consecutive 12-months, rolling total. In order to achieve the increases in production, the permittee will also be authorized to perform the following construction and work: add a new HCE washer press roll; begin first improvements to pulp machine (drying and head-box); add a new HCE evaporator train; install a new HCE blow heat recovery system to control all HCE cells; add a new HCE cell; install a new HCE washer; begin second improvements to pulp machine (drying and speed increase); and, install a new post-HCE washer. The combined projects avoid PSD preconstruction review based on the netting analysis.

This permit is issued pursuant to Chapter 403, Florida Statutes (F.S.). Any party to this order (permit) has the right to seek judicial review of the permit pursuant to Section 120.68, F.S., by the filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the Clerk of the Department in the Legal Office; and, by filing a copy of the Notice of Appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The Notice of Appeal must be filed within 30 (thirty) days from the date this Notice is filed with the Clerk of the Department.

Executed in Tallahassee, Florida.

Trina L Vielhauer

Trina L. Vielhauer, Chief
Bureau of Air Regulation

Air Permit No. 0890004-018-AC
Final Air Construction Permit
Rayonier Performance Fibers LLC

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF FINAL AIR CONSTRUCTION PERMIT (including the Final permit) was sent by certified mail (*) and copies were sent by U.S. Mail or electronically (with Received Receipt) before the close of business on 2/20/06 to the person(s) listed or as otherwise noted:

Mr. Fred J. Perrett, General Manager, Rayonier Performance Fibers LLC *
Mr. David Tudor, Application Contact, Rayonier Performance Fibers LLC
Mr. Chris Kirts, NED
Mr. David Buff, P.E., GAI

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to §120.52(7), Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Mary L Hanney (Clerk) 2/20/06 (Date)

Department of Environmental Protection

Jeb Bush
Governor

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

Colleen M. Castille
Secretary

PERMITTEE:
Rayonier Performance Fibers, LLC
The Foot of Gum Street
Fernandina Beach, Florida 32035-1309

I.D. Number:	0890004
Permit Project No.:	0890004-018-AC
Date of Issue:	February 20, 2006
Expiration Date:	March 1, 2009
County:	Nassau
Project:	Facility Modification

This permit is issued to allow an increase in the permitted throughput capacity for the facility's operations, the construction/installation of the #6 Power Boiler (PB), which replaces the three existing ones, and three evaporator bodies to thicken hot caustic extract (HCE), and to recognize the production of the No. 6 Batch Digester. The increase in production will occur in two stages and depends on the installation of some additional equipment. These changes will occur at the existing Rayonier Performance Fibers LLC's Fernandina Beach Dissolving Sulfite Pulp Mill located at The Foot of Gum Street, Fernandina Beach, Nassau County, Florida. UTM Coordinates: Zone 17; 454.7 km East; and, 3392.2 km North; Latitude: 30° 39' 44" North; and, Longitude: 81° 29' 03" West.

First, the initial increase in the facility's production will be from 153,205 to 162,000 air dried metric ton (ADMT) per consecutive 12-months, rolling total. After successful installation of a new blow heat recovery system to control VOC (volatile organic compounds) emissions from all HCE cells, production may increase to 175,000 ADMT per consecutive 12-months, rolling total. In order to achieve the increases in production, the permittee will also be authorized to perform the following construction and work: add a new HCE washer press roll; begin first improvements to pulp machine (drying and head-box); add a new HCE evaporator train; install a new HCE blow heat recovery system to control all HCE cells; add a new HCE cell; install a new HCE washer; begin second improvements to pulp machine (drying and speed increase); and, install a new post-HCE washer. The #6 PB is actually an existing used PB (obtained from another mill and built in 1983) and is being altered from a pulverized coal fired PB to a fluidized-bed wood fired PB; and, the emissions unit will replace three existing fuel-oil fired PBs, Nos. 1, 2 and 3.

STATEMENT OF BASIS: This air construction permit is issued under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawing(s), plans, and other documents, attached hereto or on file with the permitting authority, in accordance with the terms and conditions of this permit.

Referenced attachments made a part of this permit:
Title V Air Operation Permit: 0890004-011-AV
Appendix SS-1, Stack Sampling Facilities
TABLE 297.310-1, CALIBRATION SCHEDULE version dated 10/07/96
Attachment 40 CFR 60, Subpart A
FIGURE 1 - SUMMARY REPORT - GASEOUS AND OPACITY EXCESS EMISSIONS AND MONITORING SYSTEMS PERFORMANCE REPORT (40 CFR 60, July 1996)
Appendix A to 40 CFR 63, Subpart DDDDD
Appendix B to 40 CFR 63, Subpart DDDDD
Tables to 40 CFR 63, Subpart DDDDD

Michael G. Cooke
Michael G. Cooke, Director
Division of Air Resource Management

MGC/tlv/bm

"More Protection, Less Process"

Printed on recycled paper.

PERMITTEE:

Rayonier Performance Fibers, LLC
Foot of Gum Street
Fernandina Beach, Florida 32035-1339

Facility I.D. Number: 0890004
Permit/Project Number: 0890004-018-AC

GENERAL CONDITIONS:

1. The terms, conditions, requirements, limitations, and restrictions set forth in this permit are "Permit Conditions" and are binding and enforceable pursuant to Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of the conditions.

2. This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings, exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.

3. As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey any vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit is not a waiver of or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.

4. This permit conveys no title to land or water, does not constitute State recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title.

5. This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permitted to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department.

6. The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed and used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules.

7. The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at a reasonable time, access to the premises, where the permitted activity is located or conducted to:

a. Have access to and copy any record that must be kept under the conditions of the permit;

b. Inspect the facility, equipment, practices, or operations regulated or required under this permit; and

c. Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

Reasonable time may depend on the nature of the concern being investigated.

PERMITTEE:

Rayonier Performance Fibers, LLC
Foot of Gum Street
Fernandina Beach, Florida 32035-1339

Facility I.D. Number: 0890004
Permit/Project Number: 0890004-018-AC

GENERAL CONDITIONS:

8. If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately provide the Department with the following information:

    a. a description of and cause of non-compliance; and

    b. the period of non-compliance, including dates and times; or, if not corrected, the anticipated time the non-compliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the non-compliance.

The permittee shall be responsible for any and all damages, which may result and may be subject to enforcement action by the Department for penalties or for revocation of this permit.

9. In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except where such use is prescribed by Sections 403.73 and 403.111, Florida Statutes. Such evidence shall only be used to the extent it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

10. The permittee agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.

11. This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 62-4.120 and 62-730.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.

12. This permit or a copy thereof shall be kept at the work site of the permitted activity.

13. This permit also constitutes:

( ) Determination of Best Available Control Technology (BACT)
( ) Determination of Prevention of Significant Deterioration (PSD)
(X) Compliance with New Source Performance Standards (NSPS)
(X) Compliance with National Emission Standards for Hazardous Air Pollutants/ Maximum Available Control Technology (MACT)

PERMITTEE:

Rayonier Performance Fibers, LLC
Foot of Gum Street
Fernandina Beach, Florida 32035-1339

Facility I.D. Number: 0890004
Permit/Project Number: 0890004-018-AC

GENERAL CONDITIONS:

14. The permittee shall comply with the following:

a. Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.

b. The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports required by this permit, and records of all data used to complete the application for this permit. These materials shall be retained at least three years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.

c. Records of monitoring information shall include:

- the date, exact place, and time of sampling or measurements;
- the person responsible for performing the sampling or measurement;
- the dates analyses were performed;
- the person responsible for performing the analyses;
- the analytical techniques or methods used; and
- the results of such analyses.

15. When requested by the Department, the permittee shall within a reasonable time furnish any information required by law, which is needed to determine compliance with the permit. If the permittee becomes aware that relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.

SPECIFIC CONDITIONS:

A. No. 6 Power Boiler.

E.U. ID No.	Brief Description
022	Bubbling Fluidized Bed No. 6 Power Boiler with a Settling Chamber followed by an ESP for PM emissions control and a Wet Alkali Scrubber for SO_2 emissions control

Emissions Unit 022 identifies the No. 6 Power Boiler, which is a converted existing power boiler. It will be firing mostly biomass (green bark, chips, knots, fines and landscape waste), tires, No. 2 fuel oil for startup, No. 6 fuel oil (max. sulfur content of 2.5%, by weight) and small amounts of facility-generated on-spec used oil (to be blended with the No. 6 fuel oil). The boiler was originally constructed in 1983 as a traveling grate coal-fired boiler.

The converted boiler will include staged combustion and flue gas recirculation (FGR) to reduce NOx emissions. Due to the planned conversion, there is some uncertainty associated with the emissions characteristics. A selective non-catalytic reduction (SNCR) system may be installed to control NOx emissions. This would generally consist of an ammonia tank, pumps, piping, compressed air delivery, injectors, and a control system.

Particulate matter emissions will be controlled with a large settling chamber followed by an electrostatic precipitator (ESP). Large ash particles settle out in the chamber and are removed from the bottom hopper by a screw conveyor system. The design includes a four-field ESP with collector plates and rigid electrodes. Each field will have a dedicated transformer/rectifier (T/R) set and ash hopper. Ash will be removed by a screw conveyor system.

Acid gases will be controlled by a wet alkaline scrubber located after the ESP and induced draft fan. The wet scrubber will spray approximately 4000 gpm of re-circulated alkaline scrubber water over a series of chevrons and louver-type packings to reduce acid gas emissions. The design pressure drop across the system will be approximately 2 inches of water column. Emissions exhaust at a volumetric flow rate of 183,421 acfm and a temperature of 150° F through the single wet scrubber stack that will be approximately 10 feet in diameter and 190 feet above ground level.

{Permitting note(s): This emissions unit is regulated under: 40 CFR 60, Subpart D; and, 40 CFR 63, Subpart DDDDD (by 09/13/07), adopted and incorporated by reference in Rule 62-204.800, F.A.C.}

The following specific conditions apply to the emissions unit listed above:

General

A.0. General.
a. Power Boilers Nos. 1, 2 and 3 shall be permanently shutdown once Power Boiler No. 6 becomes commercially operational and has been compliance tested.
[Rules 62-4.070(3) and 62-212.400(5), F.A.C.]

b. By September 13, 2007, Power Boiler No. 6 shall be in compliance with the requirements of 40 CFR 63, Subparts A and DDDDD (including Appendices A and B), which are a part of the Title V Air Operation Permit, No. 0890004-011-AV, and incorporated by reference.

[Rules 62-4.070(3) and 62-204.800, F.A.C.; and, 40 CFR 63.7495(b)]

SPECIFIC CONDITIONS:

c. References/Acronyms.
   1. SIP: Florida's State Implementation Plan.
   2. NSPS: New Source Performance Standards.
   3. NESHAP: National Emission Standards for Hazardous Air Pollutants.
   4. AC: Air Construction Permit.
   5. PSD NSR: Prevention of Significant Deterioration New Source Review.
   6. CEMS: continuous emissions monitoring system.
   7. COMS: continuous opacity monitoring system.

d. Unless otherwise stated, the "Administrator" is the Department's "Secretary" or its designee.

e. Control Equipment.
   1. To control particulate matter, the permittee shall install a settling chamber (or equivalent) followed by a 4-field electrostatic precipitator designed to achieve at least the emissions standards specified in this permit.
   2. To control acid gases, the permittee shall install a wet alkaline scrubber designed to achieve at least the emissions standards specified in this permit.
   3. To control nitrogen oxides, the converted boiler shall be designed with staged combustion and include flue gas recirculation (FGR). In addition, the permittee is authorized to install (as necessary) a selective non-catalytic reduction system (SNCR) with ammonia injection to achieve at least the emissions standards specified in this permit.

[Rule 62-4.070(3), F.A.C.]

Operational Parameters

A.1. Permitted Capacity. The maximum heat input rates are:
   a. The maximum continuous steam production rate, 24-hour average, is 310,000 lbs/hr based on 525 MMBtu/hr heat input. Initial and annual compliance testing shall be conducted within 90% of this permitted steam rate. If the initial compliance tests cannot be performed at this level, the AC will be modified to reflect the actual installed capacity; and,
   b. The maximum annual steam production rate is 265,000 lbs/hr based on 450 MMBtu/hr heat input. This will require recordkeeping on a 12-month rolling average basis.

[Rules 62-4.070(3), 62-204.800 and 62-212.200 (PTE), F.A.C.; and, application received September 12, 2005]

A.2. Methods of Operation. This boiler may be fired with:
   a. Biomass, consisting of green bark, knots, chips, fines and landscape waste.
   b. Tire derived fuel (TDF).
   c. No. 6 fuel oil, with a maximum sulfur content of 2.5%, by weight, during startup, shutdown, or as a temporary alternate fuel during solid fuel feed upsets.
   d. Facility-generated on-specification used oil, with a maximum sulfur content of 2.5%, by weight, and shall be blended with the No. 6 fuel oil prior to firing.
   e. No. 2 fuel oil for startup.

[Application received September 12, 2005; Rule 62-710.210, F.A.C.; and, 40 CFR Part 279]

A.3. Hours of Operation. The hours of operation are not limited, i.e., 8,760 hours/year.

[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.; and, application received September 12, 2005]

PERMITTEE:

Rayonier Performance Fibers, LLC
Foot of Gum Street
Fernandina Beach, Florida 32035-1339

Facility I.D. Number: 0890004
Permit/Project Number: 0890004-018-AC

SPECIFIC CONDITIONS:

Emission Limits and Standards

*{Permitting Note: Unless otherwise specified, the averaging times for these specific conditions **A.4.** and/thru **A.11.** are based on the specified averaging time of the applicable test method.}*

A.4. Particulate Matter (PM).
a. As determined by an EPA Method 5 or 17 compliance test, PM emissions shall not exceed 0.07 lb/MMBtu heat input; nor 36.75 lbs/hr and 138.0 TPY.

[NESHAP; application received September 12, 2005; ESP design; Rule 62-4.070(3), F.A.C.; 40 CFR 63.7500(a)(1): Table 1 to Subpart DDDDD of Part 63 – Emissions Limits and Work Practice Standards: #9.a.; and, 40 CFR 63.7520(b): Table 5 to Subpart DDDDD of Part 63 – Performance Testing Requirements: #1.e.]

b. As determined by an EPA Method 5 or 5B compliance test, no owner or operator shall cause to be discharged into the atmosphere from any affected facility any gases which:
(1) Contain particulate matter in excess of 43 nanograms per joule heat input (0.10 lb per million Btu) derived from fossil fuel or fossil fuel and wood residue; nor 52.5 lbs/hr.

[NSPS; and, 40 CFR 60.42(a)(1)]

c. As determined by an EPA Method 5 compliance test, PM emissions shall not exceed 0.2 lb/MMBtu heat input of carbonaceous fuel plus 0.1 lb/MMBtu heat input of fossil fuel; nor 105 lbs/hr.

[SIP; and, Rule 62-296.410(2)(b)(2. and Chapter 62-297, F.A.C.]

A.5. Sulfur Dioxide (SO_2).
a. As determined by CEMS data, no owner or operator shall cause to be discharged into the atmosphere from any affected facility any gases which contain sulfur dioxide in excess of:
(1) 340 nanograms per joule heat input (0.80 lb per million Btu and 420 lbs/hr) derived from liquid fossil fuel or liquid fossil fuel and wood residue, and measured as any three-hour period (arithmetic average of three contiguous one-hour periods).

[NSPS; 40 CFR 60.43(a)(1); 40 CFR 60.45(g)(2); applicant requested; and, Rule 62-212.400(2)(g), F.A.C.]

b. In order to escape PSD NSR requirements and as determined by CEMS data, SO_2 emissions shall not exceed 210.0 tons per consecutive 12-month rolling total. All valid CEMS data (including startups, shutdowns and malfunctions) shall be used to determine compliance with this limit.

[Rules 62-4.160(2), 62-210.200(PTE), and 62-212.400(2)(g), F.A.C.; application received September 12, 2005; and, supplemental information received November 7, 2005]

A.6. Nitrogen Oxides (NOx).
a. As determined by CEMS data, no owner or operator shall cause to be discharged into the atmosphere from any affected facility any gases which contain nitrogen oxides, expressed as NO_2, in excess of:
(2) 129 nanograms per joule heat input (0.30 lb per million Btu and 101.20 lbs/hr), and measured as any three-hour period (arithmetic average of three contiguous one-hour periods).

[NSPS; 40 CFR 60.44(a)(2); 40 CFR 60.45(g)(3); applicant requested; and, Rule 62-212.400(2)(g), F.A.C.]

SPECIFIC CONDITIONS:

b. When different fossil fuels are burned simultaneously in any combination, the applicable standard (in ng/J) is determined by proration using the following formula:

$$PS_{NOx} = \frac{w(260)+x(86)+y(130)+z(300)}{w+x+y+z}$$

where:
PS_{NOx} = is the prorated standard for nitrogen oxides when burning different fuels simultaneously, in nanograms per joule heat input derived from all fossil fuels fired or from all fossil fuels and wood residue fired;
w = is the percentage of total heat input derived from lignite;
x = is the percentage of total heat input derived from gaseous fossil fuel;
y = is the percentage of total heat input derived from liquid fossil fuel; and,
z = is the percentage of total heat input derived from solid fossil fuel (except lignite).

[NSPS; and, 40 CFR 60.44(b)]

c. In order to escape PSD NSR requirements and as determined by CEMS data, NOx emissions shall not exceed 380.0 tons per consecutive 12-month rolling total. All valid CEMS data (including startups, shutdowns and malfunctions) shall be used to determine compliance with this limit.

[NSPS; applicant requested; 40 CFR 60.45(g); and, Rule 62-212.400(2)(g), F.A.C.]

A.7. Carbon Monoxide (CO). As determined by CEMS data, CO emissions shall not exceed 157.5 lbs/hr, 30-day rolling average; nor, 591.3 tons per consecutive 12-month rolling total. These limits are based on 0.3 lb/MMBtu heat input. All valid CEMS data (including startups, shutdowns and malfunctions) shall be used to determine compliance with this limit.

[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.; and, application and design received September 12, 2005]

A.8. Volatile Organic Compounds (VOC). As determined by an EPA Method 25A compliance test, VOC emissions shall not exceed 0.002 lb/MMBtu heat input; nor 1.05 lbs/hr and 3.94 TPY.

[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.; application received September 12, 2005; and, supplemental information received November 7, 2005]

A.9. Hydrogen Chloride. As determined by an EPA Method 26A compliance test, hydrogen chloride emissions shall not exceed 0.09 lb/MMBtu heat input. In accordance with the NESHAP, 40 CFR 63, Subpart DDDDD requirements, the permittee shall demonstrate compliance with this standard by September 13, 2007, or within 60 days of initial startup, whichever is later.

[NESHAP; 40 CFR 63.7495(b); 40 CFR 63.7500(a)(1): Table 1 to Subpart DDDDD of Part 63 – Emissions Limits and Work Practice Standards: #9.b.; and, 40 CFR 63.7520(b): Table 5 to Subpart DDDDD of Part 63 – Performance Testing Requirements: #3.e.]

SPECIFIC CONDITIONS:

A.10. Mercury. As determined by an EPA Method 29 or 101A compliance test, mercury emissions shall not exceed 0.000009 lb/MMBtu heat input. In accordance with the NESHAP, 40 CFR 63, Subpart DDDDD requirements, the permittee shall demonstrate compliance with this standard by September 13, 2007, or within 60 days of initial startup, whichever is later.

[NESHAP; 40 CFR 63.7495(b); and, 40 CFR 63.7500(a)(1): Table 1 to Subpart DDDDD of Part 63 – Emissions Limits and Work Practice Standards: #9.c.; 40 CFR 63.7520(b): Table 5 to Subpart DDDDD of Part 63 – Performance Testing Requirements: #4.e.; 40 CFR 60, Appendix A; and, 40 CFR 61, Appendix B]

A.11. Visible Emissions.
a. As determined by COMS data, no owner or operator shall cause to be discharged into the atmosphere from any affected facility any gases which:
(2) Exhibit greater than 20 percent opacity (6-minute average) except for one six-minute period per hour of not more than 27 percent opacity.

[NSPS; 40 CFR 60.42(a)(2); and, 40 CFR 60.45(g)(1)]

b. As determined by a DEP Method 9 compliance test, visible emissions shall not exceed 30 percent opacity except that a density of 40 percent opacity is permissible for not more than two minutes in any one hour.

[SIP; and, Rule 62-296.410(2)(b)1. and Chapter 62-297, F.A.C.]

A.12. Fuel Oil Sulfur Content. As determined by a lab analysis, the sulfur content of the as-fired No. 6 fuel oil shall not exceed 2.5 percent, by weight.

[Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

A.13. "On-Specification" Used Oil. The burning of "on-specification" used oil is allowed at this facility in accordance with all other conditions of this permit and the following additional conditions:
a. Only "on-specification" used oil generated by the facility shall be fired in this emissions unit. The "on-specification" used oil shall be blended with the No. 6 fuel oil prior to firing. "On-specification" used oil is defined as that which meets the 40 CFR 279 (Standards for the Management of Used Oil) specifications listed below. Used oil that does not meet all of the following specifications is considered "off-specification" oil and shall not be fired. See Specific Conditions **A.47.** and **A.48.**

CONSTITUENT / PROPERTY *	ALLOWABLE LEVEL
Arsenic	5 ppm maximum
Cadmium	2 ppm maximum
Chromium	10 ppm maximum
Lead	100 ppm maximum
Total Halogens	1000 ppm maximum
Flash Point	100 °F minimum
PCBs	less than 50 ppm

* As determined by approved methods specified in EPA Publication SW-846 (Test Methods for Evaluating Solid Waste, Physical/Chemical Methods).

[40 CFR 279.11]

SPECIFIC CONDITIONS:

b. Upon request, a certification shall be provided that the used oil (prior to blending with the No. 6 fuel oil) complies with the limits listed above, the provisions of 40 CFR 279 and 761, and shall be recorded and retained on file.

c. "On-specification" used oil may be fired as follows:

1. Any time provided the maximum concentration of PCBs is less than 2 ppm. The analysis and recordkeeping apply to each amount prior to blending even if to be blended with 90% virgin oil.
2. Only during normal operating temperature and not during startup and shutdown if the maximum concentration of $2 \leq \text{PCB} \leq 50$ ppm.

[40 CFR 279 and 761; and, Rule 62-4.070(3), F.A.C.]

Excess Emissions

{Permitting Note: The Excess Emissions Rule at Rule 62-210.700, F.A.C., cannot vary any requirement of a NSPS or NESHAP provision.}

A.14. SIP Excess Emissions – Allowed. Excess emissions resulting from startup, shutdown or malfunction shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration.

[Rule 62-210.700(1), F.A.C.]

A.15. SIP Excess Emissions – Prohibited. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown or malfunction shall be prohibited.

[Rule 62-210.700(4), F.A.C.]

A.16. NSPS Excess Emissions. Excess emission and monitoring system performance reports shall be submitted to the Administrator for each six-month period in the calendar year. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period. Each excess emission and MSP report shall include the information required in Sec. 60.7(c). Periods of excess emissions and monitoring systems (MS) downtime that shall be reported are defined as follows:

(1) Opacity. Excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 20 percent opacity, except that one six-minute average per hour of up to 27 percent opacity need not be reported.

(2) Sulfur dioxide. Excess emissions for affected facilities are defined as:

(i) Any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of sulfur dioxide as measured by a continuous monitoring system exceed the applicable standard under 40 CFR 60.43.

(3) Nitrogen oxides. Excess emissions for affected facilities using a continuous monitoring system for measuring nitrogen oxides are defined as any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards under 40 CFR 60.44.

[40 CFR 60.45(g)]

SPECIFIC CONDITIONS:

Monitoring of Operations

A.17. Determination of Process Variables.
(a) Required Equipment. The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.
(b) Accuracy of Equipment. Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.

[Rule 62-297.310(5), F.A.C.]

A.18. Steam Monitoring. The permittee shall continuously monitor the steam production rate to demonstrate compliance with the requirements of this permit.

[Rule 62-4.070(3), F.A.C.]

A.19. Electrostatic Precipitator-Wet Scrubber Control System: PM. By September 13, 2007, the owner or operator must maintain the minimum voltage and secondary current or total power input of the electrostatic precipitator at or above the operating limits established during the performance test according to 40 CFR 63.7530(c) and Table 7, 40 CFR 63, Subpart DDDDD, that demonstrated compliance with the applicable emission limit for particulate matter. See Specific Condition **A.4.c.**

[40 CFR 63.7500(a)(2): Table 2 to Subpart DDDDD of Part 63 – Emissions Limits and Work Practice Standards: #3.b.]

A.20. Mercury. By September 13, 2007, the owner or operator must comply with the following:
a. Electrostatic Precipitator-Wet Scrubber Control System. Maintain the minimum voltage and secondary current or total power input of the electrostatic precipitator at or above the operating limits established during the performance test according to 40 CFR 63.7530(c) and Table 7, 40 CFR 63, Subpart DDDDD, that demonstrated compliance with the applicable emission limits for mercury. See Specific Condition **A.10.**
b. Fuel Analysis. Maintain the fuel type or fuel mixture such that the mercury emission rates calculated according to 40 CFR 63.7530(d)(4) is less than the applicable emission limits for mercury. See Specific Condition **A.10.**

[40 CFR 63.7500(a)(2): Table 3 to Subpart DDDDD of Part 63 – Emissions Limits and Work Practice Standards: #3.b. and #6, respectively]

A.21. Hydrogen Chloride. By September 13, 2007, the owner or operator must comply with the following:
a. Wet Scrubber Control System: Maintain the minimum scrubber effluent pH, pressure drop, and liquid flow-rate at or above the operating levels established during the performance test according to 40 CFR 63.7530(c) and Table 7, 40 CFR 63, Subpart DDDDD, that demonstrated compliance with the applicable emission limit for hydrogen chloride. See Specific Condition **A.9.**
b. Fuel Analysis: Maintain the fuel type or fuel mixture such that the hydrogen chloride emission rate calculated according to 40 CFR 63.7530(d)(3) is less than the applicable emission limit for hydrogen chloride. See Specific Condition **A.9.**

[40 CFR 63.7500(a)(2): Table 4 to Subpart DDDDD of Part 63 – Emissions Limits and Work Practice Standards: #1 and #3, respectively]

SPECIFIC CONDITIONS:

Continuous Monitoring Requirements

A.22. Each owner or operator shall install, calibrate, maintain, and operate continuous monitoring systems for measuring the opacity of emissions, sulfur dioxide emissions, nitrogen oxides emissions, carbon monoxide emissions and oxygen, in accordance with 40 CFR 60.13, 40 CFR 60.45, and 40 CFR 60, Appendices B and F.

[40 CFR 60.13; 40 CFR 60.45(a); 40 CFR 60, Appendices B and F; Rule 62-4.070(3), F.A.C.; and, application project No. 0890004-018-AC]

A.23. The owner or operator shall install, calibrate, maintain, and operate a continuous flow monitoring system in accordance with 40 CFR 60, Performance Specification 6 of Appendix B and Procedure 1 of Appendix F.

[Application project No. 0890004-018-AC; and, 40 CFR 60, Appendices B and F]

A.24. For performance evaluations under 40 CFR 60.13(c) and calibration checks under 40 CFR 60.13(d), the following procedures shall be used:
(1) Methods 6, 7, and 3B, as applicable, shall be used for the performance evaluations of sulfur dioxide and nitrogen oxides continuous monitoring systems. Acceptable alternative methods for Methods 6, 7, and 3B are given in 40 CFR 60.46(d).
(2) Sulfur dioxide or nitric oxide, as applicable, shall be used for preparing calibration gas mixtures under Performance Specification 2 of Appendix B to 40 CFR 60.
(3) For affected facilities burning fossil fuel(s), the span value for a continuous monitoring system measuring the opacity of emissions shall be 80, 90, or 100 percent and for a continuous monitoring system measuring sulfur oxides or nitrogen oxides the span value shall be determined as follows:

[In parts per million]

Fossil fuel	Span value for sulfur dioxide	Span value for nitrogen oxides
Gas..................................	{1}	500
Liquid...............................	1,000	500
Solid................................	1,500	1000
Combinations.........................	1,000y + 1,500z	500(x+y) + 1,000z

{1}Not applicable.

where:
x = the fraction of total heat input derived from gaseous fossil fuel, and
y = the fraction of total heat input derived from liquid fossil fuel, and
z = the fraction of total heat input derived from solid fossil fuel.

(4) All span values computed under 40 CFR 60.45(c)(3) for burning combinations of fossil fuels shall be rounded to the nearest 500 ppm.
(5) For a fossil fuel-fired steam generator that simultaneously burns fossil fuel and non-fossil fuel, the span value of all continuous monitoring systems shall be subject to the Administrator's approval.

[40 CFR 60.45(c)]

SPECIFIC CONDITIONS:

A.25. For any continuous monitoring system installed under 40 CFR 60.45(a), the following conversion procedures shall be used to convert the continuous monitoring data into units of the applicable standards (ng/J, lb/million Btu):
(1) When a continuous monitoring system for measuring oxygen is selected, the measurement of the pollutant concentration and oxygen concentration shall each be on a consistent basis (wet or dry). Alternative procedures approved by the Administrator shall be used when measurements are on a wet basis. When measurements are on a dry basis, the following conversion procedure shall be used:

$E = CF[20.9/(20.9\text{-percent } O_2)]$

where:

E, C, F, and % O_2 are determined under 40 CFR 60.45(f).

[40 CFR 60.45(e)]

A.26. The values used in the equation under 40 CFR 60.45(e)(1) is derived as follows:
(1) E = pollutant emissions, ng/J (lb/million Btu).
(2) C = pollutant concentration, ng/dscm (lb/dscf), determined by multiplying the average concentration (ppm) for each one-hour period by 4.15×10^{4} M ng/dscm per ppm (2.59×10^{-9} M lb/dscf per ppm) where M = pollutant molecular weight, g/g-mole (lb/lb-mole). M = 64.07 for sulfur dioxide and 46.01 for nitrogen oxides.
(3) % O_2, %CO_2 = oxygen or carbon dioxide volume (expressed as percent), determined with equipment specified under 40 CFR 60.45(a).
(4) F, F_c = a factor representing a ratio of the volume of dry flue gases generated to the calorific value of the fuel combusted (F), and a factor representing a ratio of the volume of carbon dioxide generated to the calorific value of the fuel combusted (F_c), respectively. Values of F and F_c are given as follows:

- (iii) For liquid fossil fuels including crude, residual, and distillate oils, $F = 2.476 \times 10^{-7}$ dscm/J (9,220 dscf/million Btu) and $F_c = 0.384 \times 10^{-7}$ scm CO_2 /J (1,430 scf CO_2 /million Btu).
- (v) For bark $F = 2.589 \times 10^{-7}$ dscm/J (9,640 dscf/million Btu) and $F_c = 0.500 \times 10^{-7}$ scm CO_2 /J (1,840 scf CO_2 / million Btu). For wood residue other than bark $F = 2.492 \times 10^{-7}$ dscm/J (9,280 dscf/million Btu) and $Fc = 0.494 \times 10^{-7}$ scm CO_2 /J (1,860 scf CO_2 / million Btu).

(5) The owner or operator may use the following equation to determine an F factor (dscm/J or dscf/million Btu) on a dry basis (if it is desired to calculate F on a wet basis, consult the Administrator) or F_c factor (scm CO_2 /J, or scf CO_2 /million Btu) on either basis in lieu of the F or F_c factors specified in 40 CFR 60.45(f)(4):

$$F = 10^6 \frac{227.2\ (\text{pct. H}) + 95.5\ (\text{pct. C}) + 35.6\ (\text{pct. S}) + (\text{pct. N}) - 28.7\ (\text{pct. O})}{\text{GCV}}$$

$$F_c = \frac{2.0 \times 10^{-5}\ (\text{pct. C})}{\text{GCV (SI units)}}$$

$$F = 10^6 \frac{3.64(\%H) + 1.53(\%C) + 0.57(\%S) + 0.14(\%N) - 0.46(\%O)}{\text{GCV (English units)}}$$

$$F_c = \frac{20.0(\%C)}{\text{GCV (SI units)}}$$

$$Fc = \frac{321 \times 10^3(\%C)}{\text{GCV (English units)}}$$

SPECIFIC CONDITIONS:

(i) H, C, S, N, and O are content by weight of hydrogen, carbon, sulfur, nitrogen, and oxygen (expressed as percent), respectively, as determined on the same basis as GCV by ultimate analysis of the fuel fired, using ASTM method D3178-73 (Reapproved 1979), 89, or D3176-74 or 89 (solid fuels) or computed from results using ASTM method D1137-53 or 75, D1945-64, 76, 91, or 96 or D1946-77 or 90 (Reapproved 1994) (gaseous fuels) as applicable. (These five methods are incorporated by reference-see 40 CFR 60.17.)
(ii) GCV is the gross calorific value (kJ/kg, Btu/lb) of the fuel combusted determined by the ASTM test methods D2015-77 (Reapproved 1978), 96, or D5865-98 for solid fuels and D1826-77 or 94 for gaseous fuels as applicable. (These two methods are incorporated by reference-see 40 CFR 60.17.)
(iii) For affected facilities which fire both fossil fuels and non-fossil fuels, the F or F_c value shall be subject to the Administrator's approval.

(6) For affected facilities firing combinations of fossil fuels or fossil fuels and wood residue, the F or F_c factors determined by paragraphs 40 CFR 60.45(f)(4) or (f)(5) shall be prorated in accordance with the applicable formula as follows:

$$F = \sum_{i=1}^{n} X_i F_i \quad \text{or} \quad F_c = \sum_{i=1}^{n} X_i (F_c)_i$$

where:

X_i = the fraction of total heat input derived from each type of fuel (e.g. natural gas, bituminous coal, wood residue, etc.)
F_i or $(F_c)_i$ = the applicable F or F_c factor for each fuel type determined in accordance with paragraphs (f)(4) and (f)(5) of this section.
n = the number of fuels being burned in combination.

[40 CFR 60.45(f)]

Test Methods and Procedures

A.27. In conducting the performance tests required in 40 CFR 60.8, the owner or operator shall use as reference methods and procedures the test methods in Appendix A of 40 CFR 60 or other methods and procedures as specified in 40 CFR 60.46, except as provided in 40 CFR 60.8(b). Acceptable alternative methods and procedures are given in 40 CFR 60.46(d).

[40 CFR 60.46(a)]

A.28. Boiler Thermal Efficiency. In conjunction with the initial performance tests, the permittee shall determine the installed boiler's thermal efficiency while combusting 100% wood and also 100% fuel oil.

[Rule 62-4.070(3), F.A.C.]

SPECIFIC CONDITIONS:

A.29. The owner or operator shall determine compliance with the particulate matter, SO_2, and NO_x standards in 40 CFR 60.42, 60.43, and 60.44 as follows:
(1) The emission rate (E) of particulate matter, SO_2, or NO_x shall be computed for each run using the following equation:

$E = C\ F_d\ (20.9)/(20.9 - \%\ O_2)$
where:
E = emission rate of pollutant, ng/J (1b/million Btu).
C = concentration of pollutant, ng/dscm (1b/dscf).
% O_2 = oxygen concentration, percent dry basis.
F_d = factor as determined from Method 19.

[40 CFR 60.46(b)(1)]

A.30. PM Emissions.
a. For the NSPS limit, EPA Method 5 shall be used to determine the particular matter concentration (C) at affected facilities without wet flue-gas-desulfurization (FGD) systems and EPA Method 5B shall be used to determine the particulate matter concentration (C) after FGD systems. See Specific Condition **A.4.a.**

(i) The sampling time and sample volume for each run shall be at least 60 minutes and 0.85 dscm (30 dscf). The probe and filter holder heating systems in the sampling train shall be set to provide an average gas temperature of 160 ± 14 °C (320 ± 25 °F).
(ii) The emission rate correction factor, integrated or grab sampling and analysis procedure of EPA Method 3B shall be used to determine the O_2 concentration (%O_2). The O_2 sample shall be obtained simultaneously with, and at the same traverse points as, the particulate sample. If the grab sampling procedure is used, the O_2 concentration for the run shall be the arithmetic mean of the sample O_2 sample concentrations at all traverse points.
(iii) If the particulate run has more than 12 traverse points, the O_2 traverse points may be reduced to 12 provided that Method 1 is used to locate the 12 O_2 traverse points.

[40 CFR 60.46(b)(2)]

b. For the SIP limit, the test method for PM shall be EPA Method 5, incorporated and adopted by reference in Chapter 62-297, F.A.C. See Specific Condition **A.4.b.**
c. Test procedures shall meet all applicable requirements of Chapter 62-297, F.A.C.

[Rules 62-296.410(3)(b) & (c), F.A.C.]

d. A compliance test shall be conducted initially and once each federal fiscal year.

[Rule 62-297.310(7)(a)4., F.A.C.]

PERMITTEE:

Rayonier Performance Fibers, LLC
Foot of Gum Street
Fernandina Beach, Florida 32035-1339

Facility I.D. Number: 0890004
Permit/Project Number: 0890004-018-AC

SPECIFIC CONDITIONS:

A.31. Sulfur Dioxide Emissions.

a. EPA Method 6 shall be used to determine the SO_2 concentration.

(i) The sampling site shall be the same as that selected for the particulate sample. The sampling location in the duct shall be at the centroid of the cross section or at a point no closer to the walls than 1 m (3.28 ft). The sampling time and sample volume for each sample run shall be at least 20 minutes and 0.020 dscm (0.71 dscf). Two samples shall be taken during a 1-hour period, with each sample taken within a 30-minute interval.

(ii) The emission rate correction factor, integrated sampling and analysis procedure of EPA Method 3B shall be used to determine the O_2 concentration (%O_2). The O_2 sample shall be taken simultaneously with, and at the same point as, the SO_2 sample. The SO_2 emission rate shall be computed for each pair of SO_2 and O_2 samples. The SO_2 emission rate (E) for each run shall be the arithmetic mean of the results of the two pairs of samples.

[40 CFR 60.46(b)(4)]

b. A compliance test shall be conducted initially and in accordance with 40 CFR 60.8. Continuous compliance shall be demonstrated by the required emissions monitoring system.

[40 CFR 60.8; and, Rule 62-297.310(7)(a)4., F.A.C.]

A.32. Nitrogen Oxides Emissions.

a. EPA Method 7 shall be used to determine the NO_X concentration.

(i) The sampling site and location shall be the same as for the SO_2 sample. Each run shall consist of four grab samples, with each sample taken at about 15-minute intervals.

(ii) For each NO_X sample, the emission rate correction factor, grab sampling and analysis procedure of EPA Method 3B shall be used to determine the O_2 concentration (%O_2). The sample shall be taken simultaneously with, and at the same point as, the NO_X sample.

(iii) The NO_X emission rate shall be computed for each pair of NO_X and O_2 samples. The NO_X emission rate (E) for each run shall be the arithmetic mean of the results of the four pairs of samples.

[40 CFR 60.46(b)(5)]

b. A compliance test shall be conducted initially and in accordance with 40 CFR 60.8. Continuous compliance shall be demonstrated by the required emissions monitoring system.

[40 CFR 60.8; and, Rule 62-297.310(7)(a)4., F.A.C.]

A.33. CO Emissions. The test method for carbon monoxide emissions shall be EPA Method 10, incorporated in Chapter 62-297, F.A.C. A compliance test shall be conducted initially and in accordance with 40 CFR 60.8. Continuous compliance shall be demonstrated by the required emissions monitoring system.

[40 CFR 60.8; and, Rules 62-297.401 and 62-297.310(7)(a)4., F.A.C.]

A.34. VOC Emissions.

a. The test method for VOC emissions shall be EPA Method 25A, incorporated in Chapter 62-297, F.A.C. A compliance test shall be conducted initially and in accordance with 40 CFR 60.8.; and, once every five years for renewal.

[40 CFR 60.8; and, Rules 62-297.401 and 62-297.310(7)(a)4., F.A.C.]

SPECIFIC CONDITIONS:

A.35. Visible Emissions.
a. For the NSPS limit, EPA Method 9 and the procedures in 40 CFR 60.11 shall be used to determine opacity. Compliance shall be demonstrated by COMS. See Specific Condition **A.11.a.**

[40 CFR 60.11; and, 40 CFR 60.46(b)(3)]

b. For the SIP limit, the test method for visible emissions shall be DEP Method, incorporated in Chapter 62-297, F.A.C. See Specific Conditions **A.11.b.** and **A.36.**
c. Test procedures shall meet all applicable requirements of Chapter 62-297, F.A.C.

[Rules 62-296.410(3)(a) & (c), F.A.C.]

d. A compliance test shall be conducted initially and in accordance with 40 CFR 60.8. Continuous compliance shall be demonstrated by COMS.

[40 CFR 60.8; and, Rule 62-297.310(7)(a)4., F.A.C.]

A.36. DEP Method 9. The provisions of EPA Method 9 (40 CFR 60, Appendix A) are adopted by reference with the following exceptions:
1. EPA Method 9, Section 2.4, Recording Observations. Opacity observations shall be made and recorded by a certified observer at sequential fifteen second intervals during the required period of observation.
2. EPA Method 9, Section 2.5, Data Reduction. For a set of observations to be acceptable, the observer shall have made and recorded, or verified the recording of, at least 90 percent of the possible individual observations during the required observation period. For single-valued opacity standards (e.g., 20 percent opacity), the test result shall be the highest valid six-minute average for the set of observations taken. For multiple-valued opacity standards (e.g., 20 percent opacity, except that an opacity of 40 percent is permissible for not more than two minutes per hour) opacity shall be computed as follows:

a. For the basic part of the standard (i.e., 20 percent opacity) the opacity shall be determined as specified above for a single-valued opacity standard.

b. For the short-term average part of the standard, opacity shall be the highest valid short-term average (i.e., two-minute, three-minute average) for the set of observations taken.

In order to be valid, any required average (i.e., a six-minute or two-minute average) shall be based on all of the valid observations in the sequential subset of observations selected, and the selected subset shall contain at least 90 percent of the observations possible for the required averaging time. Each required average shall be calculated by summing the opacity value of each of the valid observations in the appropriate subset, dividing this sum by the number of valid observations in the subset, and rounding the result to the nearest whole number. The number of missing observations in the subset shall be indicated in parenthesis after the subset average value.

[Rule 62-297.401, F.A.C.]

SPECIFIC CONDITIONS:

A.37. Fuel Analyses. For Power Boiler No. 6, the following fuel sampling and analysis protocol shall be used:
a. Determine and record the as-fired fuel sulfur content, percent by weight, for liquid fuels using either ASTM D2622-92, ASTM D4294-90, both ASTM D4057-88 and ASTM D129-91, or the latest edition, by analyzing a representative sample of the blended fuel oil following each fuel delivery.
b. Record hourly fuel totalizer readings with calculated hourly feed rates for each fuel fired, the ratio of fuels fired, the density of each fuel, and the percent sulfur content, by weight, of each fuel.
c. The analyses of the No. 6 fuel oil, as received from the supplier in a bill of lading, shall include the following:
1. Density (ASTM D 1298-80 or the latest edition).
2. Calorific heat value in Btu per pound (ASTM D 240-76 or the latest edition).
3. Sulfur content, by weight (ASTM D2622-92, ASTM D4294-90, both ASTM D4057-88 and ASTM D129-91, or the latest edition).

d. On a quarterly basis, an analyses of the wood fuel shall include the following:
1. Calorific heat value in Btu per pound (ASTM D2015-77, or the latest edition).
2. Moisture content (ASTM D2016-74, 83, or the latest edition).
3. Sulfur content, by weight (Test Methods for Evaluating Solid Waste, Physical/Chemical Methods: EPA Publication SW-846 Third Edition (November 1986), or the latest edition).

[40 CFR 60, Subpart A]

A.38. Required Number of Test Runs. For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured provided, however, that three complete and separate determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the owner or operator, and a valid third run cannot be obtained within the five day period allowed for the test, the Secretary or his or her designee may accept the results of the two complete runs as proof of compliance, provided that the arithmetic mean of the results of the two complete runs is at least 20 percent below the allowable emission limiting standards.

[Rule 62-297.310(1), F.A.C.]

A.39. Operating Rate During Testing.
a. Testing of emissions shall be conducted with each emissions unit operation at permitted capacity, which is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impracticable to test at permitted capacity, an emissions unit may be tested at less than the minimum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test load until a new test is conducted. Once the emissions unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity.

[Rules 62-297.310(2) & (2)(b), F.A.C.]

b. If the new emissions unit is unable to achieve the designed permitted capacity (at least 90%) for the initial tests, then this permit will be revised to reflect the true installed capacity.

[Rule 62-4.070(3), F.A.C.]

SPECIFIC CONDITIONS:

A.40. Calculation of Emission Rate. The indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the separate test runs unless otherwise specified in a particular test method or applicable rule.

[Rule 62-297.310(3), F.A.C.]

A.41. Applicable Test Procedures.

(a) Required Sampling Time.

1. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes.

2. Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:

c. The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.

(b) Minimum Sample Volume. Unless otherwise specified in the applicable rule, the minimum sample volume per run shall be 25 dry standard cubic feet.

(c) Required Flow Rate Range. For EPA Method 5 particulate sampling, acid mist/sulfur dioxide, and fluoride sampling which uses Greenburg Smith type impingers, the sampling nozzle and sampling time shall be selected such that the average sampling rate will be between 0.5 and 1.0 actual cubic feet per minute, and the required minimum sampling volume will be obtained.

(d) Calibration of Sampling Equipment. Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1 (attached).

(e) Allowed Modification to EPA Method 5. When EPA Method 5 is required, the following modification is allowed: the heated filter may be separated from the impingers by a flexible tube.

[Rule 62-297.310(4), F.A.C.]

A.42. Required Stack Sampling Facilities. When a mass emissions stack test is required, the permittee shall comply with the requirements contained in Appendix SS-1, Stack Sampling Facilities, attached to this permit.

[Rule 62-297.310(6), F.A.C.]

SPECIFIC CONDITIONS:

A.43. Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.

(a) General Compliance Testing.

2. For excess emission limitations for particulate matter specified in Rule 62-210.700, F.A.C., a compliance test shall be conducted annually while the emissions unit is operating under soot blowing conditions in each federal fiscal year during which soot blowing is part of normal emissions unit operation, except that such test shall not be required in any federal fiscal year in which a fossil fuel steam generator does not burn liquid fuel for more than 400 hours other than during startup.

3. The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision. In renewing an air operation permit pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal:

   a. Did not operate; or

   b. In the case of a fuel burning emissions unit, burned liquid fuel for a total of no more than 400 hours.

4. During each federal fiscal year (October 1 – September 30), unless otherwise specified by rule, order, or permit, the owner or operator of each emissions unit shall have a formal compliance test conducted for:

   a. Visible emissions, if there is an applicable standard;

   b. Each of the following pollutants, if there is an applicable standard, and if the emissions unit emits or has the potential to emit: 5 tons per year or more of lead or lead compounds measured as elemental lead; 30 tons per year or more of acrylonitrile; or 100 tons per year or more of any other regulated air pollutant; and

   c. Each NESHAP pollutant, if there is an applicable emission standard.

5. An annual compliance test for particulate matter emissions shall not be required for any fuel burning emissions unit that, in a federal fiscal year, does not burn liquid fuel, other than during startup, for a total of more than 400 hours.

9. The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.

(b) Special Compliance Tests. When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it may require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department.

(c) Waiver of Compliance Test Requirements. If the owner or operator of an emissions unit that is subject to a compliance test requirement demonstrates to the Department, pursuant to the procedure established in Rule 62-297.620, F.A.C., that the compliance of the emissions unit with an applicable weight emission limiting standard can be adequately determined by means other than the designated test procedure, such as specifying a surrogate standard of no visible emissions for particulate matter sources equipped with a bag house or specifying a fuel analysis for sulfur dioxide emissions, the Department shall waive the compliance test requirements for such emissions units and order that the alternate means of determining compliance be used, provided, however, the provisions of Rule 62-297.310(7)(b), F.A.C., shall apply.

[Rule 62-297.310(7), F.A.C.; and, SIP approved]

SPECIFIC CONDITIONS:

Recordkeeping and Reporting Requirements

A.44. Notification.
a. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department's NED office in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department's NED.

[Rule 62-210.700(6), F.A.C.]

b. If CEMS or COMS data indicates non-compliance, the permittee shall notify the Department's NED office within one working day of such determination.

[Rule 62-4.070(3), F.A.C.]

A.45. Plant Operation - Problems. If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the owner or operator shall notify the Department as soon as possible, but at least within one (1) working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; the steps being taken to correct the problem and prevent future recurrence; and where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit and the regulations.

[Rule 62-4.130, F.A.C.]

A.46. Test Reports.
(a) The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department's NED on the results of each such test.
(b) The required test report shall be filed with the Department's NED as soon as practical but no later than 45 days after the last sampling run of each test is completed.
(c) The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the Department's NED to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information:

1. The type, location, and designation of the emissions unit tested.
2. The facility at which the emissions unit is located.
3. The owner or operator of the emissions unit.
4. The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.
5. The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.
6. The type of air pollution control devices installed on the emissions unit, their general condition, their normal operating parameters (pressure drops, total operating current and GPM scrubber water), and their operating parameters during each test run.
7. A sketch of the duct within 8 stack diameters upstream and 2 stack diameters downstream of the sampling ports, including the distance to any upstream and downstream bends or other flow disturbances.
8. The date, starting time and duration of each sampling run.
9. The test procedures used, including any alternative procedures authorized pursuant to Rule 62-297.620, F.A.C. Where optional procedures are authorized in this chapter, indicate which option was used.
10. The number of points sampled and configuration and location of the sampling plane.
11. For each sampling point for each run, the dry gas meter reading, velocity head, pressure drop across the stack, temperatures, average meter temperatures and sample time per point.

SPECIFIC CONDITIONS:

12. The type, manufacturer and configuration of the sampling equipment used.
13. Data related to the required calibration of the test equipment.
14. Data on the identification, processing and weights of all filters used.
15. Data on the types and amounts of any chemical solutions used.
16. Data on the amount of pollutant collected from each sampling probe, the filters, and the impingers, are reported separately for the compliance test.
17. The names of individuals who furnished the process variable data, conducted the test, analyzed the samples and prepared the report.
18. All measured and calculated data required to be determined by each applicable test procedure for each run.
19. The detailed calculations for one run that relate the collected data to the calculated emission rate.
20. The applicable emission standard, and the resulting maximum allowable emission rate for the emissions unit, plus the test result in the same form and unit of measure.
21. A certification that, to the knowledge of the owner or his authorized agent, all data submitted are true and correct. When a compliance test is conducted for the Department or its agent, the person who conducts the test shall provide the certification with respect to the test procedures used. The owner or his authorized agent shall certify that all data required and provided to the person conducting the test are true and correct to his knowledge.

[Rules 62-213.440 and 62-297.310(8), F.A.C.]

A.47. Monthly records shall be kept of the quantity of "on-specification" used oil fired in these emissions units. The above records shall be maintained in a form suitable for inspection, retained for a minimum of five years, and be made available upon request. See Specific Conditions **A.13.** and **A.48.**

[Rule 62-213.440(1)(b)2.b., F.A.C.; and, 40 CFR 279.61 and 761.20(e)]

A.48. The permittee shall include in the "Annual Operating Report for Air Pollutant Emitting Facility" a summary of the "on-specification" used oil fired in the No. 6 Power Boiler during the calendar year. See Specific Conditions **A.13.** and **A.47.**

[Rule 62-213.440(1)(b)2.b., F.A.C.]

A.49. NSPS Excess Emission and Monitoring System Performance Reports. Excess emission and monitoring system performance reports shall be submitted to the Administrator for each six-month period in the calendar year. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period. Each excess emission and MSP report shall include the information required in Sec. 60.7(c). Periods of excess emissions and monitoring systems (MS) downtime that shall be reported are defined as follows:
(1) Opacity. Excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 20 percent opacity, except that one six-minute average per hour of up to 27 percent opacity need not be reported.
(2) Sulfur dioxide. Excess emissions for affected facilities are defined as:
(i) Any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of sulfur dioxide as measured by a continuous monitoring system exceed the applicable standard established under 40 CFR 60.43. See Specific Condition **A.5.a.(1).**
(3) Nitrogen oxides. Excess emissions for affected facilities using a continuous monitoring system for measuring nitrogen oxides are defined as any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards under 40 CFR 60.44. See Specific Condition **A.6.a.(2).**

[40 CFR 60.45(g)(1), (2) & (3)]

SPECIFIC CONDITIONS:

A.50. Within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of such facility and at such other times as may be required by the Administrator under section 114 of the Act, the owner or operator of such facility shall conduct performance test(s) and furnish the Administrator a written report of the results of such performance test(s).

[40 CFR 60.8(a)]

A.51. Performance tests shall be conducted and data reduced in accordance with the test methods and procedures contained in each applicable subpart unless the Administrator:
(1) Specifies or approves, in specific cases, the use of a reference method with minor changes in methodology;
(2) Approves the use of an equivalent method;
(3) Approves the use of an alternative method the results of which he has determined to be adequate for indicating whether a specific source is in compliance;
(4) Waives the requirement for performance tests because the owner or operator of a source has demonstrated by other means to the Administrator's satisfaction that the affected facility is in compliance with the standard; or
(5) Approves shorter sampling times and smaller sample volumes when necessitated by process variables or other factors. Nothing in 40 CFR 60.8 shall be construed to abrogate the Administrator's authority to require testing under section 114 of the Act.

[40 CFR 60.8(b)(1), (2), (3), (4) & (5)]

A.52. Performance tests shall be conducted under such conditions as the Administrator shall specify to the plant operator based on representative performance of the affected facility. The owner or operator shall make available to the Administrator such records as may be necessary to determine the conditions of the performance tests. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a performance test nor shall emissions in excess of the level of the applicable emission limit during periods of startup, shutdown, and malfunction be considered a violation of the applicable emission limit unless otherwise specified in the applicable standard.

[40 CFR 60.8(c)]

A.53. The owner or operator of an affected facility shall provide the Administrator at least 30 days prior notice of any performance test, except as specified under other subparts, to afford the Administrator the opportunity to have an observer present. If after 30 days notice for an initially scheduled performance test, there is a delay (due to operational problems , etc) in conducting the scheduled performance test, the owner or operator of an affected facility shall notify the administrator (or delegated State or local agency) as soon as possible of any delay in the original test date, either by providing at least 7 days prior notice of the rescheduled date of the performance test, or by arranging a rescheduled date with the Administrator (or delegated State or local agency) by mutual agreement.

[40 CFR 60.8(d)]

SPECIFIC CONDITIONS:

A.54. The owner or operator of an affected facility shall provide, or cause to be provided, performance testing facilities as follows:
(1) Sampling ports adequate for test methods applicable to such facility. This includes
(i) constructing the air pollution control system such that volumetric flow rates and pollutant emission rates can be accurately determined by applicable test methods and procedures and
(ii) providing a stack or duct free of cyclonic flow during performance tests, as demonstrated by applicable test methods and procedures.
(2) Safe sampling platform(s).
(3) Safe access to sampling platform(s).
(4) Utilities for sampling and testing equipment.

[40 CFR 60.8(e)(1), (2), (3) & (4)]

A.55. Unless otherwise specified in the applicable subpart, each performance test shall consist of three separate runs using the applicable test method. Each run shall be conducted for the time and under the conditions specified in the applicable standard. For the purpose of determining compliance with an applicable standard, the arithmetic means of results of the three runs shall apply. In the event that a sample is accidentally lost or conditions occur in which one of the three runs must be discontinued because of forced shutdown, failure of an irreplaceable portion of the sample train, extreme meteorological conditions, or other circumstances, beyond the owner or operator's control, compliance may, upon the Administrator's approval, be determined using the arithmetic mean of the results of the two other runs.

[40 CFR 60.8(f)]

B. <u>No. 6 Batch Digester</u>.

B.1. The new No. 6 batch digester is in operation and included in with the "batch digesters" under Emissions Unit 005, Vent Gas Scrubber and Direct Contact Condenser", and is subject to the terms and conditions established for this emissions unit in Title V permit, No. 0890004-011-AV, specifically in Subsection G., which is incorporated by reference.

{Emission Unit 005 includes the vent gas scrubber (wet scrubber), which controls emissions from numerous vents from the cooking acid plant, the red stock washers, the unwashed stock tank, the spent sulfite liquor storage tanks, the spent sulfite liquor washer area, the digesters, and the blow pits. The scrubber is a packed bed containing 10 feet of packing consisting of two packed sections. The lower section is designed for sulfur dioxide emissions control via gas absorption using alkaline scrubbing media (soda ash, sodium hydroxide, etc.). The spent scrubber media is bled first to other closed sources to make maximum use of the alkali to remove sulfur dioxide, and then to sewer via closed piping to number 1 Pump Station. The sulfur dioxide concentration in the stack is continuously measured with a CMS.

The upper packed section of the vent gas scrubber is designed to condense methanol from the gas stream by direct contact with fresh well water, i.e. the Direct Contact Condenser. This is a once through process. The condensed methanol held in the water is sent to the biological effluent treatment system for treatment in order to comply with the requirements of 40 CFR 63, Subpart S.}

PERMITTEE:

Rayonier Performance Fibers, LLC
Foot of Gum Street
Fernandina Beach, Florida 32035-1339

Facility I.D. Number: 0890004
Permit/Project Number: 0890004-018-AC

SPECIFIC CONDITIONS:

C. Multiple Effect Evaporators (3 bodies).

C.1. The permittee is authorized to install three (3) new Multiple Effect Evaporators (MEEs) bodies, which are refurbished existing units. They will form a new train to be used to increase the solids concentration of weak HCE, a byproduct stream from the manufacturing process that can be used at Kraft mills as a sodium source. All of the MEEs will vent through a common condenser used to collect methanol and then vented to the atmosphere via the sulfur dioxide recovery scrubber for the recovery boiler. The new bodies will be lumped in with the two sets of MEEs and will now be described as "three" sets of MEEs under Emissions Unit 021, and subject to the terms and conditions established for this emissions unit in Title V permit, No. 0890004-011-AV, specifically in Subsection G., which is incorporated by reference.

{Emissions Unit 021 includes the Evaporator Vents Methanol Condenser System. The steam that is used to eject the vent gases from the two sets of multiple effect evaporators along with the evaporator vent gases themselves, are piped to a pre-condenser which condenses the steam followed by the main condenser which condenses the methanol. The water used to condense the steam and methanol is reclaimed from the biological effluent treatment system after the methanol has been digested.

The condensate from the pre-condenser and the main condenser are sewered to the biological effluent treatment system via the Number 3 Pump Station for compliance with the 40 CFR 63, Subpart S requirements.

The non-condensable gases from the main condenser are sent to the multi-stage wet scrubber/Brinks Demister at the Recovery boiler (Emissions Unit No. 006).}

D. Facility.

D.1. Capacity.
a. Except as provided below, the facility's production shall not exceed 162,000 air dried metric tons (ADMT) per consecutive 12-months, rolling total.
b. Upon successful installation and submittal of the engineering report of the HCE blow heat recovery system to control VOC emissions from all of the HCE cells, the facility's production shall not exceed 175,000 ADMT per consecutive 12-months, rolling total.

[Rules 62-4.070(3), 210.200(PTE) and 62-212.400(5), F.A.C.]

D.2. The application indicates the following preliminary schedule for commencing construction:

Date	Activity
February 2006	Add a new HCE washer press roll
February 2007	Begin first improvements to pulp machine (drying and head-box)
	Add a new HCE evaporator train
February 2008	Install a new HCE blow heat recovery system to control all HCE cells
	Add a new HCE cell
	Install a new HCE washer
	Begin second improvements to pulp machine (drying and speed increase)
	Install a new post-HCE washer

* It is noted that some of the later changes are contingent on the success of the earlier stages.

SPECIFIC CONDITIONS:

D.3. The permittee is authorized to perform the following construction and work:

a. add a new HCE washer press roll;
b. begin first improvements to pulp machine (drying and head-box);
c. add a new HCE evaporator train; install a new HCE blow heat recovery system to control all HCE cells;
d. add a new HCE cell;
e. install a new HCE washer; begin second improvements to pulp machine (drying and speed increase); and,
f. install a new post-HCE washer.

The permittee shall obtain prior written approval for any substantial changes to the work described above and in the application for this project.

D.4. Within fourteen (14) days of completing each of the above stages of work, the permittee shall provide a written notice of the following:

a. type of work;
b. date completed;
c. deviations form original proposal; and,
d. a discussion of any emissions impacts.

D.5. Attached to each required Annual Operating Report, the permittee shall provide a summary of the following to the compliance authority:

a. a summary of work performed to date;
b. a summary of work remaining;
c. a preliminary schedule for completing any remaining work; and,
d. the current production capacity of the mill (ADMT per year).

D.6. Performance tests.

a. Prior to increasing plant production beyond 162,000 ADMT per year, the permittee shall install a new HCE blow heat recovery system designed to reduce VOC emissions by 60% from all HCE cells. Upon successful completion of this system, the permittee shall conduct an engineering study to determine the effectiveness of this system in capturing and reducing VOC emissions to achieve designed efficiency . A test protocol shall be submitted to the Department for review and approval prior to commencing the engineering study. Within 60 days of completing the engineering study, the permittee shall submit a report summarizing: the final installed design, material flow rates, emissions, emissions capture, emissions control, and any necessary adjustments.

[Rule 62-4.070(3), F.A.C.]

E. Miscellaneous.

E.1. Report of Actual Emissions. The permittee shall maintain and submit actual annual emissions for a period of 5 years following completion of each project phase. Emissions related to demand growth that could have been accommodated prior to the project must be shown and discussed. This requirement shall be fulfilled by submittal of a report in conjunction with the required Annual Operating Report.

[Rule 62-4.070(3) and 62-212.400(5), F.A.C.]

E.2. Testing While Burning TDF. A one-time test shall be conducted while burning the maximum percentage of TDF expected using EPA Method 29 pursuant to 40 CFR 60, Appendix A, and Chapter 62-297, F.A.C.

[Rule 62-4.070(3) and Chapter 62-297, F.A.C.; and, 40 CFR 60, Appendix A]

SPECIFIC CONDITIONS:

F. <u>Bleach Plant</u>.

F.1. The dissolving-grade bleaching system shall achieve compliance with the bleach plant provisions of 40 CFR 63.445 *as expeditiously as practicable*, but in no event later than 4 years from the issuance of this air construction permit.

[40 CFR 63.440(d)(2) and 63.445]

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Rayonier Performance Fibers LLC
Fernandina Beach Mill
The Foot of the Gum Tree
Post Office Box 2002
Fernandina Beach, FL 32035-1309

PS Form 3800, May 2000 See Reverse for Instructions

Rayonier

Performance Fibers

Fernandina Mill

February 3, 2006

Certified Mail, Return Receipt Requested

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BUREAU OF AIR REGULATION

Mr. Bruce Mitchell, P.E.
Florida Dept. of Environmental Protection
Bureau of Air Regulation
Division of Air Resource Management
2600 Blair Stone Road, M.S. 5505
Tallahassee, FL 32399-2400

Re: Public Notice of Intent to Issue an Air Construction Permit
Rayonier Performance Fibers, Fernandina Mill

Dear Mr. Mitchell:

David Tudor requested that I send you the attached certified copy of the Public Notice of Intent to Issue an Air Construction Permit.

If you have any questions, please contact David Tudor at 904-277-1452 or david.tudor@rayonier.com.

Yours very truly,

Tricia Harrell

Tricia Harrell
Technical Administrator

PUBLIC NOTICE OF INTENT TO ISSUE AN AIR CONSTRUCTION PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
Draft Air Construction Permit No.: 0890004-018-AC
Rayonier Performance Fibers LLC
Nassau County

The Department of Environmental Protection (permitting authority) gives notice of its intent to issue an Air Construction Permit for the facility modifications requested for Rayonier Performance Fibers LLC's existing sulfite mill, located at The Foot of Gum Street, Nassau County. The applicant's name and address are: Mr. F. J. Perrett, General Manager, Rayonier Performance Fibers LLC, Fernandina Beach Mill, The Foot of Gum Street, P.O. Box 2002, Fernandina Beach, Florida 32035-1309.

The subject of the Air Construction Permit is to initially increase the facility's production from 153,205 to 162,000 air dried metric ton (ADMT) per consecutive 12-months, rolling total. After successful installation of a new blow heat recovery system to control VOC (volatile organic compounds) emissions from all HCE (hot caustic extract) cells, production may increase to 175,000 ADMT per consecutive 12-months, rolling total. In order to achieve the increases in production, the permittee will also be authorized to perform the following construction and work: add a new HCE washer press roll; begin first improvements to pulp machine (drying and head-box); add a new HCE evaporator train; install a new HCE blow heat recovery system to control all HCE cells; add a new HCE cell; install a new HCE washer; begin second improvements to pulp machine (drying and speed increase); and, install a new post-HCE washer. The new #6 PB is actually an existing used PB (obtained from another mill and built in 1983) and is being altered from a pulverized coal fired PB to a fluidized-bed wood fired PB; and, the emissions unit will replace three existing fuel-oil fired PBs, Nos. 1, 2 and 3. Based on the application and conditions of the draft permit, the project is not subject to preconstruction review for the Prevention of Significant Deterioration (PSD), Rule 62-212.400, F.A.C. The application is structured such that potential emissions from the "new" boiler net out of PSD preconstruction review due to the shutdown of the old power boilers. The combined projects net out of PSD preconstruction review based on the planned installation of additional pollution controls; requested emissions caps, and the applicant's projected actual emissions.

The permitting authority will issue the Final Air Construction Permit in accordance with the conditions of the Draft Air Construction Permit unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The permitting authority will accept written comments concerning the proposed Draft Air Construction Permit issuance action for a period of 14 (fourteen) days from the date of publication of this Notice. Written comments should be provided to the Department's Bureau of Air Regulation, 2600 Blair Stone Road, Mail Station #5505, Tallahassee, Florida 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in this Draft Air Construction Permit, the permitting authority shall issue a Revised Draft Air Construction Permit and require, if applicable, another Public Notice.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative hearing in accordance with Sections 120.569 and 120.57 of the Florida Statutes (F.S.). The petition must contain the information set forth below and must be filed (received) in Office of General Counsel of the Department of Environmental Protection, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000 (Telephone: 850/245-2241; Fax: 850/245-2303). Petitions filed by any persons other than those entitled to written notice under Section 120.60(3), F.S., must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of the notice of intent, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the permitting authority for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above, at the time of filing. The failure of any person to file a petition within the applicable time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57, F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205, F.A.C.

A petition that disputes the material facts on which the permitting authority's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner; the name, address and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when each petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, as well as the rules and statutes which entitle the petitioner to relief; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and, (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the permitting authority's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the permitting authority's final action may be different from the position taken by it in this notice of intent. Persons whose substantial interests will be affected by any such final decision of the permitting authority on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

Mediation is not available for this proceeding.

A complete project file is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

Permitting Authority:
Department of Environmental Protection
Bureau of Air Regulation
111 South Magnolia Drive, Suite 4
Tallahassee, Florida 32301
Telephone: 850/488-0114
Fax: 850/922-6979

Affected District:
Department of Environmental Protection
Northeast District
7825 Baymeadows Way, Suite 200-B
Jacksonville, Florida 32202
Telephone: 904/807-3300
Fax: 904/488-4363

The complete project file includes the Technical Evaluation and Preliminary Determination and associated Draft Air Construction Permit, the application(s), and the information submitted by the facility's representative, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact Jeffery F. Koerner, P.E., at the above address, or call 850/921-9536, for additional information.
1t 02-01-2006
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STATE OF FLORIDA
COUNTY OF NASSAU:

Before the undersigned authority personally appeared **Michael B. Hankins** who on oath says that he is the Advertising Director of The Fernandina Beach *News-Leader*, a weekly newspaper published at Fernandina Beach in Nassau County, Florida; that the attached copy of advertisement, being a Legal Notice in the matter of

PUBLIC NOTICE OF INTENT TO ISSUE AN AIR CONSTRUCTION PERMIT
State of Florida
Department of Environmental Protection
Rayonier Performance Fibers LLC

was published in said newspaper in the issues of
02-01-2006
ref. No. 4910

Affiant further says that the said Fernandina Beach *News-Leader* is a newspaper published at Fernandina Beach, in said Nassau County, Florida, and that the said newspaper has heretofore been continuously published in said Nassau County, Florida, each week and has been entered as second class mail matter at the post office in Fernandina Beach in said Nassau County, Florida, for a period of one year next preceding the first publication of the attached copy of advertisement; and affiant further says that he has neither paid nor promised any person, firm or corporation any discount, rebate, commission or refund for the purpose of securing this advertisement for publication in the said newspaper.

Michael B. Hankins

Sworn to and subscribed before me this **1st** day of **February, A.D. 2006.**

Robert O. Fiege

Robert O. Fiege, Notary Public

✓ Personally Known

NOTARY PUBLIC STATE OF FLORIDA
ROBERT O. FIEGE
MY COMMISSION # DD317112
EXPIRES: May 31, 2008
1-800-3-NOTARY Fl. Notary Discount Assoc. Co.

Memorandum Florida Department of Environmental Protection

INTEROFFICE MEMORANDUM

TO: Trina Vielhauer

THRU: Jeff Koerner JK

FROM: Bruce Mitchell BM

DATE: January 30, 2006

SUBJECT: Rayonier Performance Fibers, LLC
Draft Air Constrution Permit
0890004-018-AC

Attached is the Draft Air Construction Permit, Project No. 0890004-018-AC. We are reissuing this permitting package due to a change that is considered to be significant, specifically the "CO" limit at Specific Condition A.7. Also, "tires" was changed to "TDF" and the No. 2 fuel oil was added for startup (normally supplements the carbonaceous fuel with No. 6 fuel oil).

The subject of the Air Construction Permit is to initially increase in the facility's production from 153,205 to 162,000 air dried metric ton (ADMT) per consecutive 12-months, rolling total. After successful installation of a new blow heat recovery system to control VOC (volatile organic compounds) emissions from all HCE cells, production may increase to 175,000 ADMT per consecutive 12-months, rolling total. In order to achieve the increases in production, the permittee will also be authorized to perform the following construction and work: add a new HCE (hot caustic extract) washer press roll; begin first improvements to pulp machine (drying and head-box); add a new HCE evaporator train; install a new HCE blow heat recovery system to control all HCE cells; add a new HCE cell; install a new HCE washer; begin second improvements to pulp machine (drying and speed increase); and, install a new post-HCE washer. The new #6 PB is actually an existing used PB (obtained from another mill and built in 1983) and is being altered from a pulverized coal fired PB to a fluidized-bed wood fired PB; and, the emissions unit will replace three existing fuel-oil fired PBs, Nos. 1, 2 and 3.

Today is Day 7 of the permitting clock.

Attachments

TLV/jk/bm

Jeb Bush
Governor

Department of Environmental Protection

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

Colleen M. Castille
Secretary

January 30, 2006

CERTIFIED MAIL – Return Receipt Requested

Mr. F. J. Perrett
General Manager
Rayonier Performance Fibers LLC
Fernandina Beach Mill
The Foot of Gum Street
P.O. Box 2002
Fernandina Beach, Florida 32035-1309

RE: Request for Facility Modifications
Air Construction Project No.: 0890004-018-AC

Dear Mr. Perrett:

One copy of the Technical Evaluation and Preliminary Determination, the Public Notice, and the Draft Air Construction Permit for the facility modifications requested for Rayonier Performance Fibers LLC's existing sulfite mill, located at The Foot of Gum Street, Nassau County, is enclosed. The permit package sent to you on January 26, 2006, is hereby withdrawn. The permitting authority's "INTENT TO ISSUE AN AIR CONSTRUCTION PERMIT" and the "PUBLIC NOTICE OF INTENT TO ISSUE AN AIR CONSTRUCTION PERMIT" are also included.

The "PUBLIC NOTICE OF INTENT TO ISSUE AN AIR CONSTRUCTION PERMIT" must be published as soon as possible. Proof of publication, i.e., newspaper affidavit, must be provided to the permitting authority's office within 7 (seven) days of publication pursuant to Rule 62-110.106(5), F.A.C. Failure to publish the notice and provide proof of publication within the allotted time may result in the denial of the permits pursuant to Rule 62-110.106(11), F.A.C.

Please submit any written comments you wish to have considered concerning the permitting authority's proposed action to Jeffrey F. Koerner, P.E., at the above letterhead address. If you have any other questions, please contact Bruce Mitchell at 850/413-9198.

Sincerely,

Trina L. Vielhauer
Chief
Bureau of Air Regulation

TLV/jfk/bm

Enclosures

In the Matter of an
Application for Permit by:

Rayonier Performance Fibers LLC
The Foot of Gum Street
Fernandina Beach, Florida 32035-1309
_______________________________________/

Draft Air Construction Permit No.: 0890004-018-AC
Nassau County

INTENT TO ISSUE AN AIR CONSTRUCTION PERMIT

The Department of Environmental Protection (permitting authority) gives notice of its intent to issue An Air Construction Permit (copy of the Draft Air Construction Permit attached) for the facility's modifications detailed in the application specified above, for the reasons stated below.

The permittee, Rayonier Performance Fibers LLC, submitted a request on November 18, 2005, for an Air Construction (AC) Permit for facility modifications located at The Foot of Gum Street, Fernandina Beach, Nassau County.

The subject of the Air Construction Permit is to initially increase the facility's production from 153,205 to 162,000 air dried metric ton (ADMT) per consecutive 12-months, rolling total. After successful installation of a new blow heat recovery system to control VOC (volatile organic compounds) emissions from all HCE cells, production may increase to 175,000 ADMT per consecutive 12-months, rolling total. In order to achieve the increases in production, the permittee will also be authorized to perform the following construction and work: add a new HCE (hot caustic extract) washer press roll; begin first improvements to pulp machine (drying and head-box); add a new HCE evaporator train; install a new HCE blow heat recovery system to control all HCE cells; add a new HCE cell; install a new HCE washer; begin second improvements to pulp machine (drying and speed increase); and, install a new post-HCE washer. The #6 PB is actually an existing used PB (obtained from another mill and built in 1983) and is being altered from a pulverized coal fired PB to a fluidized-bed wood fired PB; and, the emissions unit will replace three existing fuel-oil fired PBs, Nos. 1, 2 and 3.

The permitting authority has permitting jurisdiction under the provisions of Chapter 403, Florida Statutes (F.S.), and Chapters 62-4, 62-210 and 62-212, F.A.C. This modification is not exempt from permitting procedures. The permitting authority has determined that an Air Construction Permit is required for the proposed modification.

The permitting authority intends to issue the Air Construction Permit based on the belief that reasonable assurances have been provided to indicate that operation of the source will not adversely impact air quality, and the source will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-256, 62-257, 62-281, 62-296, and 62-297, F.A.C.

Pursuant to Sections 403.815 and 403.087, F.S., and Rules 62-110.106 and 62-210.350(3), F.A.C., you (the applicant) are required to publish at your own expense the enclosed "PUBLIC NOTICE OF INTENT TO ISSUE AN AIR CONSTRUCTION PERMIT." The notice shall be published one time only as soon as possible in the legal advertisement section of a newspaper of general circulation in the area affected. For the purpose of these rules, "publication in a newspaper of general circulation in the area affected" means publication in a newspaper meeting the requirements of Sections 50.011 and 50.031, F.S., in the county where the activity is to take place. If you are uncertain that a newspaper meets these requirements, please contact the permitting authority at the address or telephone number listed below. The applicant shall provide proof of publication to the Department's Bureau of Air Regulation, 2600 Blair Stone Road, Mail Station #5505, Tallahassee, Florida 32399-2400 (Telephone: 850/488-1344; Fax: 850/922-6979), within 7 (seven) days of publication. Failure to publish the notice and provide proof of publication within the allotted time may result in the denial of the permit pursuant to Rule 62-110.106, F.A.C.

The permitting authority will issue the Final Air Construction Permit, in accordance with the conditions of the attached Draft Air Construction Permit unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The permitting authority will accept written comments concerning the proposed Air Construction Permit issuance action for a period of 14 (fourteen) days from the date of publication of the "PUBLIC NOTICE OF INTENT TO ISSUE AN AIR CONSTRUCTION PERMIT." Written comments should be provided to the permitting authority office. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in this Draft Air Construction Permit, the permitting authority shall issue a Revised Draft Air Construction Permit and require, if applicable, another Public Notice.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative hearing in accordance with Sections 120.569 and 120.57, F.S. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department of Environmental Protection, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000 (Telephone: 850/245-2241; Fax: 850/245-2303). Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under Section 120.60(3), F.S., must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the permitting authority for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above, at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57, F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205, F.A.C.

A petition that disputes the material facts on which the permitting authority's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner; the name, address and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when each petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, as well as the rules and statutes which entitle the petitioner to relief; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and, (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the permitting authority's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the permitting authority's final action may be different from the position taken by it in this notice of intent. Persons whose substantial interests will be affected by any such final decision of the permitting authority on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

Mediation will not be available in this proceeding.

Persons subject to regulation pursuant to any federally delegated or approved air program should be aware that Florida is specifically not authorized to issue variances or waivers from any requirements of any such federally delegated or approved program. The requirements of the program remain fully enforceable by the Administrator of the United States Environmental Protection Agency and by any person under the Clean Air Act unless and until the Administrator separately approves any variance or waiver in accordance with the procedures of the federal program.

Executed in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Trina L. Vielhauer
Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this INTENT TO ISSUE AN AIR CONSTRUCTION PERMIT (including the PUBLIC NOTICE and Draft Air Construction Permit) and all copies were sent by certified mail before the close of business on 1/30/06 to the person(s) listed:

Mr. F. J. Perrett, General Manager, Rayonier Performance Fibers LLC, Fernandina Beach Mill, The Foot of Gum Street, P.O. Box 2002, Fernandina Beach, Florida 32035-1309

In addition, the undersigned duly designated deputy agency clerk hereby certifies that copies of this INTENT TO ISSUE AN AIR CONSTRUCTION PERMIT (including the PUBLIC NOTICE and Draft Air Construction Permit) were sent by U.S. mail or electronically (Received Receipt requested) on the same date to the person(s) listed:

Mr. Chris Kirts, NED
Mr. David Buff, P.E., GAI
Mr. David Tudor, Application Contact, Rayonier Performance Fibers LLC

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on This date, pursuant to Section 120.52(7), Florida Statutes, with the designated agency Clerk, receipt of which is hereby acknowledged.

[signature] 1/30/06
(Clerk) (Date)

PUBLIC NOTICE OF INTENT TO ISSUE AN AIR CONSTRUCTION PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

Draft Air Construction Permit No.: 0890004-018-AC

Rayonier Performance Fibers LLC
Nassau County

The Department of Environmental Protection (permitting authority) gives notice of its intent to issue an Air Construction Permit for the facility modifications requested for Rayonier Performance Fibers LLC's existing sulfite mill, located at The Foot of Gum Street, Nassau County. The applicant's name and address are: Mr. F. J. Perrett, General Manager, Rayonier Performance Fibers LLC, Fernandina Beach Mill, The Foot of Gum Street, P.O. Box 2002, Fernandina Beach, Florida 32035-1309.

The subject of the Air Construction Permit is to initially increase the facility's production from 153,205 to 162,000 air dried metric ton (ADMT) per consecutive 12-months, rolling total. After successful installation of a new blow heat recovery system to control VOC (volatile organic compounds) emissions from all HCE (hot caustic extract) cells, production may increase to 175,000 ADMT per consecutive 12-months, rolling total. In order to achieve the increases in production, the permittee will also be authorized to perform the following construction and work: add a new HCE washer press roll; begin first improvements to pulp machine (drying and head-box); add a new HCE evaporator train; install a new HCE blow heat recovery system to control all HCE cells; add a new HCE cell; install a new HCE washer; begin second improvements to pulp machine (drying and speed increase); and, install a new post-HCE washer. The #6 PB is actually an existing used PB (obtained from another mill and built in 1983) and is being altered from a pulverized coal fired PB to a fluidized-bed wood fired PB; and, the emissions unit will replace three existing fuel-oil fired PBs, Nos. 1, 2 and 3.

Based on the application and conditions of the draft permit, the project is not subject to preconstruction review for the Prevention of Significant Deterioration (PSD), Rule 62-212.400, F.A.C. The application is structured such that potential emissions from the "new" boiler net out of PSD preconstruction review due to the shutdown of the old power boilers. The combined projects net out of PSD preconstruction review based on the planned installation of additional pollution controls, requested emissions caps, and the applicant's projected actual emissions.

The permitting authority will issue the Final Air Construction Permit in accordance with the conditions of the Draft Air Construction Permit unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The permitting authority will accept written comments concerning the proposed Draft Air Construction Permit issuance action for a period of 14 (fourteen) days from the date of publication of this Notice. Written comments should be provided to the Department's Bureau of Air Regulation, 2600 Blair Stone Road, Mail Station #5505, Tallahassee, Florida 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in this Draft Air Construction Permit, the permitting authority shall issue a Revised Draft Air Construction Permit and require, if applicable, another Public Notice.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative hearing in accordance with Sections 120.569 and 120.57 of the Florida Statutes (F.S.). The petition must contain the information set forth below and must be filed (received) in Office of General Counsel of the Department of Environmental Protection, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000 (Telephone: 850/245-2241; Fax: 850/245-2303). Petitions filed by any persons other than those entitled to written notice under Section 120.60(3), F.S., must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of the notice of intent, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the permitting authority for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above, at the time of filing. The failure of any person to file a petition within the applicable time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57, F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205, F.A.C.

A petition that disputes the material facts on which the permitting authority's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner; the name, address and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when each petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, as well as the rules and statutes which entitle the petitioner to relief; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and, (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the permitting authority's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the permitting authority's final action may be different from the position taken by it in this notice of intent. Persons whose substantial interests will be affected by any such final decision of the permitting authority on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

Mediation is not available for this proceeding.

A complete project file is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

Permitting Authority:
Department of Environmental Protection
Bureau of Air Regulation
111 South Magnolia Drive, Suite 4
Tallahassee, Florida 32301
Telephone: 850/488-0114
Fax: 850/922-6979

Affected District:
Department of Environmental Protection
Northeast District
7825 Baymeadows Way, Suite 200-B
Jacksonville, Florida 32202
Telephone: 904/807-3300
Fax: 904/488-4363

The complete project file includes the Technical Evaluation and Preliminary Determination and associated Draft Air Construction Permit, the application(s), and the information submitted by the facility's representative, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact Jeffery F. Koerner, P.E., at the above address, or call 850/921-9536, for additional information.

TECHNICAL EVALUATION
&
PRELIMINARY DETERMINATION

PROJECT

Draft Air Construction Permit No. 0890004-018-AC
New Power Boiler No. 6 and Digester No. 6 Project

COUNTY

Nassau County, Florida

APPLICANT

Rayonier Performance Fibers LLC
Fernandina Beach Dissolving Sulfite Pulp Mill
ARMS Facility ID No. 0890004

PERMITTING AUTHORITY

Florida Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation
Air Permitting North Program

January 30, 2006
(Revised)

{Filename: TEPD - Rayonier - Revised}

1. GENERAL PROJECT INFORMATION

Facility Description and Location

The applicant operates an existing Dissolving Sulfite Pulp Mill (SIC No. 2611) in Fernandina Beach at the Foot of Gum Street in Nassau County, Florida 32305: The UTM coordinates are Zone 14, 454.7 km East, and 3392.2 km North. This site is in an area that is in attainment (or designated as unclassifiable) for all air pollutants subject to a National Ambient Air Quality Standard (NAAQS).

The mill uses a sulfite (ammonia-base) process to produce various grades of chemical cellulose from pine wood-chips. There are only two other pulp mills located in the United States that produce products similar to the Fernandina Mill and neither of these mills use the same type of manufacturing process. This plant produces approximately 10 different grades of cellulose each with different specifications and customers. The amount of each grade of product that is produced is based on market demand. The cellulose produced at this mill goes into such products as plastics, photographic film, LCD screens, paints, cigarette filters, pharmaceuticals, food products, cosmetics and textiles. Customers of these products have stringent quality requirements. This mill produces approximately 150,000 tons of performance fibers annually.

Existing Process Description

The following process description of the existing facility was provided by the applicant.

The sulfite process utilizes a sulfurous acid and ammonium bisulfite cooking solution to chemically separate the lignin from the cellulose. This is accomplished in six batch pressure vessels called digesters. The "cooking" process requires approximately 6 hours. The pulp and spent cooking solution (SSL – spent sulfite liquor) are separated over vacuum washers called red stock washers. The pulp continues into the screening area while the SSL is pumped to the evaporators. The cooking solution is prepared in the "acid plant". All of the sulfur dioxide which is not captured in the acid making or emitted from the digestion and red stock washer processes is collected and scrubbed in the vent gas scrubber utilizing caustic soda. In this scrubbing tower is a second section for condensing a cooking process by-product, methanol. The methanol is condensed and sent to the effluent treatment system for biological digestion.

Unbleached sulfite pulp from the digesters has un-cooked woody materials called knots and tailings which must be screened from the pulp. Knotters and Cowan screens are utilized to remove these materials. The knots and tailings are collected and pressed for utilization as fuel in the power boilers.

Pulp exiting the screening operation enters the bleach plant. One bleaching stage is called Hot Caustic Extraction (HCE). This is a batch stage utilizing caustic soda to remove small chain cellulose molecules called hemi-cellulose from the pulp. This process uses small pressure vessels called HCE cells. No sulfur compounds are used in this stage. A spent solution washed from the pulp after this stage is called hot caustic extract (HCE) and is sold to kraft mills for its sodium content and energy value. This stage also has methanol as a by product in the vent gas, but presently it is not captured.

Pulp leaving the hot caustic stage is further purified in continuous and batch stages using peroxide, chlorine dioxide, chlorine, sodium hydroxide, and sodium hypochlorite depending on the pulp grade specifications. Following these "bleaching" stages the pulp passes through centrifugal dirt cleaners on the way to the pulp machine. The pulp machine forms the sheet by draining water from pulp slurry containing 99% water over a moving wire to a consistency of 50% water. The remainder of the water is removed by passing the pulp sheet over pressing and drying cylinders heated internally with steam. The sheet is wound on a "jumbo" roll which when completed weighs over 10 tons. The final sheet only has about 7% moisture. No coating occurs on any of the grades produced.

The jumbo rolls are transported to the finishing room where the pulp sheet is cut into smaller rolls or sheets which fit the customers' processes. The finished rolls or bales are shipped to the customer based on their order. No pulp is produced without an order due to the very specific quality requirements and sheet size for each customer.

The digestion, hot caustic extraction stage and pulp machine are high users of steam for heating. The steam is produced in three 1939 vintage power boilers utilizing bark and No. 6 oil for fuel. Steam is also used to produce about 90 percent of the mills electricity needs. The boiler's emissions are cleaned with venturi-type scrubbers.

The spent sulfite liquor (SSL) from the digestion process and the hot caustic extract (HCE) are pumped to the evaporators. From the evaporators the SSL is burned in the recovery boiler. This 1976 boiler provides steam for the evaporators and its emissions are scrubbed for sulfur dioxide removal using an ammonia solution. The ammonium bisulfite produced in the scrubber is used for cooking acid make-up. The emissions are further cleaned with mist filters that remove the ammonium sulfate particulate formed in the scrubber. Methanol from the evaporator vents is piped to condensers which collect the methanol and send it to the biological treatment system.

Regulatory Categories

Title III: The plant is a potential major source of hazardous air pollutants (HAPs).

Title IV: The plant has no units subject to the acid rain provisions of the Clean Air Act.

Title V: The plant is a Title V major source of air pollution in accordance with Chapter 213, F.A.C.

PSD: The plant is a PSD-major facility in accordance with Rule 62-212.400, F.A.C.

NSPS: The plant operates units are subject to New Source Performance Standards in 40 CFR 60.

NESHAP: The plant operates units subject to National Emissions Standards for HAPs in 40 CFR 63.

Project Description

The applicant proposes two changes to the plant:

1. The applicant requests that the digester production limit be increased from 153,205 to 162,000 ADMT per year. At a later date, the applicant intends to install a blow heat recovery system on the vent from the cooking process, which accounts for approximately 80% of the volatile organic compounds (VOC) generated from the bleaching system. The blow heat recovery system will remove approximately 60% of the VOC emissions from the cooking process vent. After the blow heat recovery system is installed, the applicant requests that the production limit be increased from 162,000 to 175,000 ADMT per year. To realize the requested full production level, the applicant proposes to conduct the following work: add a new HCE washer press roll; begin first improvements to pulp machine (drying and head-box); add a new HCE evaporator train; install a new HCE blow heat recovery system to control all HCE cells; add a new HCE cell; install a new HCE washer; begin second improvements to pulp machine (drying and speed increase); and install a new post-HCE washer.
2. The applicant proposes to permanently shut down Power Boiler Nos. 1 – 3 and install a new bubbling bed boiler (Power Boiler No. 6) with a maximum heat input rate of 525 MMBtu per hour (450 MMBtu per hour, annual average). The new unit will primarily fire bark/wood, tire-derived fuel (TDF) as a supplemental fuel, and No. 6 residual oil as a startup and supplemental fuel. Also, small amounts of on-specification used oil generated on site will be fired for energy recovery. The "new" unit will be a refurbished coal-fired boiler with the following controls: settling chamber (ash hopper); 4-field electrostatic precipitator (ESP); alkaline wet scrubber; staged combustion; flue gas recirculation (FGR); and the capability to add Selective Non-Catalytic Reduction (SNCR) as necessary to comply with the requested NOx standard. The application is structured such that potential emissions from the "new" boiler net out of PSD preconstruction review due to the shutdown of the old power boilers.

Therefore, the project affects the proposed new Power Boiler No. 6 and the following existing emissions units: power boilers 1 – 3 (EUs 001, 002, and 003); digesters/pulping system (EU-005), recovery boiler (EU-006), wastewater treatment (WWT) system (EU-010); bleaching system (EU-011), and evaporators (EU-021).

Processing Schedule

09/12/05 Received application for a minor source air pollution construction permit; incomplete.

10/24/05 Received additional information.

11/07/05 Received additional information.

12/19/05 Received additional information.

01/23/06: Received additional information; complete.

2. APPLICABLE REGULATIONS

State Regulations

This project is subject to the applicable environmental laws specified in Section 403 of the Florida Statutes (F.S.). The Florida Statutes authorize the Department of Environmental Protection to establish rules and regulations regarding air quality as part of the Florida Administrative Code (F.A.C.). This project is subject to the applicable rules and regulations defined in the following Chapters of the Florida Administrative Code: 62-4 (Permitting Requirements); 62-204 (Ambient Air Quality Requirements, PSD Increments, and Federal Regulations Adopted by Reference); 62-210 (Permits Required, Public Notice, Reports, Stack Height Policy, Circumvention, Excess Emissions, and Forms); 62-212 (Preconstruction

Review); 62-213 (Title V Air Operation Permits for Major Sources of Air Pollution); 62-296 (Emission Limiting Standards); and 62-297 (Test Methods and Procedures, Continuous Monitoring Specifications, and Alternate Sampling Procedures). Specifically, the proposed project will be subject to the following primary applicable state requirements:

Rule 62-212.400, F.A.C. – Preconstruction Review for the Prevention of Significant Deterioration (PSD) of Air Quality

The Department regulates major air pollution sources in accordance with Florida's Prevention of Significant Deterioration (PSD) program, as defined in Rule 62-212.400, F.A.C. A PSD review is required in areas currently in attainment with the state and federal Ambient Air Quality Standards (AAQS) or areas designated as "unclassifiable" for a given pollutant. A new facility is considered "major" with respect to PSD if it emits or has the potential to emit: 250 tons per year or more of any regulated air pollutant; or 100 tons per year or more of any regulated air pollutant and the facility belongs to one of the 28 PSD Major Facility Categories (Table 62-212.400-1, F.A.C.); or 5 tons per year of lead.

For new projects at existing PSD-major facilities, each regulated pollutant is reviewed for PSD applicability based on emissions thresholds known as the Significant Emission Rates listed in Table 62-212.400-2, F.A.C. Pollutant emissions from the proposed project exceeding these rates are considered "significant" and the applicant must employ the Best Available Control Technology (BACT) to minimize emissions of each such pollutant and evaluate the air quality impacts. Although a facility may be *major* with respect to PSD for only one regulated pollutant, it may be required to install BACT controls for several *significant* regulated pollutants. The current project is proposed at an existing PSD-major facility. PSD applicability to the project will be discussed in the next section.

Rule 62-296.410, F.A.C. - Carbonaceous Fuel Burning Equipment

This rule regulates emissions of particulate matter and opacity from carbonaceous fuel burning equipment. Proposed Power Boiler No. 6 was originally constructed in 1983 and had the capability of firing bark/wood. For purposes of this rule, an "existing unit" is an emissions unit which was in existence, in operation, or under construction, or had received a permit to begin construction prior to January 18, 1972. Therefore, Power Boiler No. 6 will be considered a "new" boiler subject to Rule 62-296.410, F.A.C.

62-296.406, F.A.C. - Fossil Fuel Fired Steam Generators with a Maximum Heat Input Rate of 250 MMBtu/hour

This rule regulates NOx, PM, SO_2, and opacity from fossil fuel fired steam generators with a maximum heat input rate of 250 MMBtu per hour. Proposed Power Boiler No. 6 was originally constructed in 1983 and had a maximum fossil fuel heat input rate of 540 MMBtu per hour. For purposes of this rule, an "existing unit" is an emissions unit which was in existence, in operation, or under construction, or had received a permit to begin construction prior to January 18, 1972. Therefore, Power Boiler No. 6 will be considered a "new" boiler subject to Rule 62-296.406, F.A.C. The rule establishes the emissions standards specified in NSPS Subpart D as the applicable standards.

Federal Regulations

The facility is subject to applicable federal provisions regarding air quality as established by the EPA in the Code of Federal Regulations (CFR). In general, these regulations establish either New Source Performance Standards (NSPS) for new, modified or reconstructed units or National Emissions Standards for Hazardous Air Pollutants (NESHAP) for existing, new, or reconstructed units. Existing units at the facility are subject to portions of the following regulations in 40 CFR 63: Subpart A (General Provisions); Subpart S (NESHAP for Pulp and Paper Industry); Subpart MM (NESHAP for Chemical Recovery Combustion Sources at Kraft, Soda, Sulfite, and Stand-Alone Semi chemical Pulp Mills); and Subpart DDDDD (Industrial, Commercial and Institutional Boilers and Process Heaters). The proposed project will not change the regulated status of any existing unit. New Power Boiler No. 6 will be subject to the applicable requirements of NSPS Subpart DDDDD for existing units as described under the separate section of this report.

3. PSD APPLICABILITY REVIEW FOR PROJECT

Plant History

In the late 1990's, a digester exploded at the Stone Container Mill in Panama City, Florida. The pulp and paper industry began a program to inspect and repair (as necessary) each digester at existing plants to ensure overall safety. In 1998, the Department allowed Rayonier to install a sixth digester to allow the plant to meet current contracts while one digester was shut down for inspection and repair.

Several years later in 2002, the Department issued an after-the-fact air construction permit (No. 0890004-010-AC) that limited plant production to 153,205 air-dried metric tons (ADMT) per year, which identified the capacity of approximately 5 active digesters. Specific Condition 4 of the permit states, "If there is any increase in annual pulp production (153,205

ADMT/year) by the batch digesters, Nos. 1 thru 6, then PSD New Source Review pursuant to Rule 62-212.400(5), F.A.C., shall apply to all major SO_2 emissions units at the facility." Specific Condition 5 of the permit effectively limits SO_2 emissions from the vent gas scrubber system to 276.82 tons per year. This scrubber controls the digesters, vents from the cooking acid plant, red stock washers, unwashed stock tank, spent sulfite liquor storage tanks, spent sulfite washer area, and the blow pits. Emissions from the scrubber are monitored by CEMS. So, the intent of the restriction was to provide an opportunity for a PSD review related to increased SO_2 emissions from the additional digester activity.

The plant is now subject to NESHAP Subpart S in 40 CFR 63. In accordance with the MACT requirements, a condenser/scrubber system was installed in 2001 to reduce methanol (HAP) emissions from the pulping operation. The condenser/scrubber system also reduces VOC and SO_2 emissions.

Regulatory Background

The applicability of PSD preconstruction review for a given project is defined in Rule 62-212.400, F.A.C. (Prevention of Significant Deterioration of Air Quality) and Rule 62-210.200, F.A.C. (Definitions). Florida's PSD preconstruction review program is currently based on EPA's original program, which compares past actual emissions to future potential emissions when determining whether an emissions increase will occur. Subsequent to a 1990 court decision (WEPCO Decision), EPA revised the federal PSD program for electric utility steam generating units to allow a comparison of past actual emissions to future representative actual emissions when determining whether an emissions increase will occur. Florida's current PSD program includes this provision for electric utility steam generating units. In 2002, EPA again revised the federal PSD regulations to allow all industries to compare baseline actual emissions to projected actual emissions when determining whether an emissions increase will occur. Florida has proposed revised rules to incorporate this change. The proposed rule changes will be finalized before the final permit for this project is issued.

Applicant's Review

Digester Project

Fully utilizing the additional capacity of existing Digester No. 6 in the digester/pulping system will also require minor changes to the bleaching system, evaporators, and the WWT system. The existing recovery boiler does not require any physical changes, operational changes, or permit revisions to accommodate any increase in digester production. The permitted capacity of the recovery boiler is 70,000 lb/hour of spent sulfite liquor (SSL). The recovery boiler has repeatedly demonstrated compliance at this level. In 2003 and 2004, the recovery boiler operated at an average SSL burning rate of 68,000 lb/hour for more than 500 hours. The applicant maintains that the current permitted SSL burning rate is sufficient to address any future demand growth up to the requested production level. The unit has successfully operated at this maximum level and demonstrated compliance at this level. The applicant notes that the Department's proposed New Source Review Reform regulations state the following:

"(215) Projected Actual Emissions - The maximum annual rate, in tons per year, 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 design capacity or its 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 major stationary source. One year is one 12-month period. In determining the projected actual emissions, the Department:

(a) Shall consider all relevant information, including historical operational data, the company's own representations, the company's expected business activity and the company's highest projections of business activity, the company's filings with the State or Federal regulatory authorities, and compliance plans or orders, including consent orders; and

(b) Shall include fugitive emissions to the extent quantifiable and emissions associated with startups and shutdowns; and

(c) 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 product demand growth; or

(d) In lieu of using the method set out in paragraphs (a) through (c) above, may be directed by the owner or operator to use the emissions unit's potential to emit, in tons per year."

The requested digester production increase is related to an anticipated increase in market demand for the industry. Production at the Fernandina Beach plant is limited to advance orders because of the unique specifications placed on the specialty fibers requested by each customer. Three similar plants in the United States have recently closed and a fourth is planning to close in 2006. The proposed changes to the digester operations will allow the plant to respond to this anticipated growth in demand for their products.

For SO_2 emissions, the applicant estimated baseline actual SO_2 emissions (2002/2003) from the recovery boiler of 836 tons per year and projected actual emissions of 1073 tons per year at full production after changes to the digester operations. The permitted allowable SO_2 emissions are 1409.92 tons per year. However, the applicant notes that any emissions increases from recovery boiler would be due to "*demand growth*" realized after the digester project. Based on the Department's proposed rules, the emissions increases from the recovery boiler may be excluded from the projected actual emissions because the unit is fully capable of accommodating the additional production without any physical, operational, or permitting changes. Excluding the difference in emissions due to future demand growth would show no emissions increases from the recovery boiler. Therefore, the project to fully utilize the digester production capacity will only affect the following existing emissions units that are actually undergoing a change: digesters/pulping system; bleaching system; evaporators; and the WWT system.

Prior to adding the 6th digester in 1998, the actual annual production was 149,957 ADMT/year in 1996 and 149,426 in 1997. The applicant used the 1996 level of production to calculate the percent increase based on the request to increase production to 162,000 ADMT/year (8% increase) and eventually to 175,000 ADMT/year (16.7% increase). The following table summarizes the emissions from the digester production increase.

Table 3A. Digester Production Increase – Applicant's PSD Netting Analysis

Unit	Summary of Net Emissions Increases (Tons/Year) [a]		
	CO	SO_2	VOC [b]
Digesters/Pulping System	---	10.9	2.9 / 6.1
Bleaching System	25.1	---	14.2 / (-41.5)
Evaporators	---	---	4.3 / 9.0
WWT System	---	---	5.3 / 11.1
Total Net Change	25	11	27 / (-15)
PSD Significant Emissions Rate	100	40	40 / 40
Subject to PSD Review?	No	No	No / No

a. Except for VOC, emissions increases are based on the full 16.7% production increase.

b. For VOC, the first figure identifies future projected actual emissions based on an 8% production increase (162,000 ADMT/year) with no control from the proposed blow heat recovery system. The second figure considers the full 16.7% digester production increase (175,000 ADMT/year), but includes the proposed HCE blow heat recovery system on the bleaching plant to conservatively reduce VOC emissions by approximately 60%.

c. Applicant based emission increases on projected actual emissions resulting from the requested production increase.

Boiler Replacement Project

The applicant is also proposing to replace the existing three power boilers with a single new power boiler primarily due to excessive maintenance and repair costs for the older units. In addition, the proposed bubbling bed power boiler will allow the plant to fire bark/wood available from the plant as the primary fuel, which will reduce operating costs. The applicant views the two projects as separate and distinct projects that should be reviewed independently. The boiler replacement project considers the shutdown of Power Boiler Nos. 1 – 3 (EUs 001 – 003) as emissions decreases and the new Power Boiler No. 6 as emissions increases. As shown in the following table, the applicant concludes that the boiler replacement project will net out of PSD preconstruction review when considered as a separate project.

Table 3B. Boiler Replacement Project – Applicant's PSD Netting Analysis

Unit	Summary of Net Emissions Increases (Tons/Year)					
	CO	NOx	PM	PM_{10} [b]	SO_2	VOC
Baseline (Power Boilers 1 – 3)	(-690.8)	(-341.0)	(-276.1)	(-242.5)	(-182.0)	0 [a]
Proposed Power Boiler No. 6	591.3 ~~394.2~~	380.0	138.0	138	210.0 [d]	3.9
Total Net Change	(-100 ~~297~~) [c]	39	(-138)	(-105)	28	3.9
PSD Significant Emissions Rate	100	40	25	15	40	40
Subject to PSD Review?	No	No	No		No	No

Notes:

a. Applicant estimates ~ 45 tons per year from the old units, but assumed "0" because it is difficult to determine.

b. Applicant's estimation for PM_{10}.

c. ~~Substituted applicant's potential annual CO emission rate (394.2 tons/year) identified in the application form, which was higher than identified in applicant's netting summary.~~ Based on 0.3 lb/MMBtu and 450 MMBtu per hour.

d. Applicant's information provided on 12/19/05 incorrectly included 10.9 tons/year of SO_2 increases from the 16.7% production increase. Accordingly, the requested cap on SO_2 emissions was adjusted down to 210 tons/year.

Applicant's Conclusion

Based on the separate project reviews presented, the applicant concludes that neither the boiler replacement project nor the digester production increase project is subject to PSD preconstruction review.

Department's Review

Digester Project

The digester project requires changes for the following affected units: bleaching system, evaporators, and wastewater (WWT) treatment system. CO and SO_2 emissions increases from these units will be minimal. Actual VOC emissions increases could exceed the PSD significant emissions rate of 40 tons/year with the full production increase to 175,000 ADMT/year. However, the plant will restrict production to 162,000 AMDT/year or less until HCE blow heat recovery system is installed, which will reduce actual emissions of methanol, VOC, and SO_2 emissions. Once the HCE blow heat recovery system is installed and satisfactorily tested, the plant may operate at full production capacity (175,000 AMDT/year) because this system will actually result in a decrease in VOC emissions and not an increase.

With regard to consideration of the recovery boiler, this project includes the following unique factors:

- There are 6 existing active digesters at this plant. Due to an industrial accident at another Florida plant, the Department allowed the installation of the 6th digester in 1998 as a safety/maintenance project. An after-the-fact air construction permit (Permit No. 0890004-010-AC) was issued in 2002 with a digester/pulping system production limit of 153,205 ADMT per year to ensure that the installation of the 6th digester did not allow a PSD-significant emissions increase for SO_2 without a PSD applicability review. The proposed project would relax this limit and requires a PSD applicability review for SO_2 emissions in accordance with Condition No. 4 in Permit No. 0890004-010-AC.
- To realize the increased production capacity, only minor physical and/or operational changes are needed for the digester/pulping system, bleaching system, evaporators, and the WWT system. The permittee will also install an additional condenser scrubber to remove methanol, SO_2, and VOC emissions prior increasing operations to full capacity (175,000 ADMT per year). These are all affected units.
- In 2000, SO_2 emissions from the pulping operation were approximately 70 tons/year. A condenser/scrubber system was installed in 2001 to reduce methanol (HAP) emissions from the pulping operation pursuant to NESHAP Subpart S. Combined with a revamped scrubber system SO_2 emissions were also reduced. In 2004, estimated SO_2 emissions from the pulping operation were approximately 11 tons per year. Assuming a 16.7% increase from 2004 emissions, SO_2 emissions would increase approximately 2 tons/year from the pulping operation.
- The current Title V permit specifies the following capacity of the recovery boiler and SO_2 limits: 70,000 lb/hour of

spent sulfite liquor (SSL); 321.9 lb of SO2/hour and 1409.92 tons of SO2/year.

- Plant records show that the recovery boiler operated near this permitted capacity for over 570 periods based on 48-hour moving averages during the 2003 – 2004 operating years. Records also indicate that the recovery boiler has demonstrated compliance near this specified capacity. No physical, operational, or permitting changes to the recovery boiler are necessary to accommodate any increase in digester production.

- The Department also reviewed previous Annual Operating Reports to compare past SO2 emissions from the recovery boiler with past production levels from 1995 through 2004, as summarized in the following table.

Year	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
Production, ADMT/Yr	143,953	149,957	149,426	132,016	119,689	151,515	146,247	145,895	144,975	145,883
SO_2, TPY	1097	1087	1149	929	950	1067	829	1075	876	797
lb SO_2 per ADMT	15.2	14.5	15.4	14.1	15.9	14.1	11.3	14.7	12.1	10.9

The above table shows that there is not a direct, linear correlation between production and SO2 emissions from the recovery boiler. There are other important factors influencing emissions such as wood material availability, fuel availability, actual fuel sulfur content, SO2 removal in the scrubber, etc. The table also shows a general trend of decreasing SO2 emissions from the recovery boiler. For example, baseline actual SO2 emissions for 1996/1997 would be 1118 tons/year, which is actually higher than the applicant's projected actual emissions (1073 tons/year) after the proposed project.

- The application was submitted in September of 2005. The Department anticipates a final version of its New Source Review Reform regulations in February of 2006. Under the new regulations, an applicant may compare projected actual emissions to baseline actual emissions from an existing unit. In determining the projected actual emissions, the new regulation states that the Department 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 product demand growth. As indicated above, the recovery boiler is physically capable of accommodating any increase due to demand growth and is not otherwise restricted by permit condition. Based on the proposed regulations, the project would not trigger PSD preconstruction review.

Rule 62-210.200(11)(b), F.A.C. states, "*The Department may presume that unit-specific allowable emissions for an emissions unit are equivalent to the actual emissions of the emissions unit provided that, for any regulated air pollutant, such unit-specific allowable emissions limits are federally enforceable.*" The Department uses this discretion with care and previous instances have been infrequent. However, this project presents unique circumstances as described above, particularly with regard to timing of the pending rule changes which would show no PSD-significant emissions increase. To satisfy current regulations at the time of issuance for the draft permit and acknowledging that the proposed regulations will be in effect when the final permit is issued, the Department presumes actual SO2 emissions from the recovery boiler to be equivalent to the unit-specific allowable emissions (1409.92 tons/year) before the project as well as after the project. Therefore, there is no increase in SO2 emissions from the recovery boiler. For purposes of Condition No. 4 in Permit No. 0890004-010-AC increasing the digester production limit to 175,000 ADMT per year will not result in a PSD-significant net SO2 emissions increase.

Boiler Replacement Project

As shown in the applicant's netting analysis, the new bubbling bed Power Boiler No. 6 is expected to result in actual decreases for CO, PM/PM10, and VOC emissions compared to the old power boilers. CO, NOx and SO2 emissions from the new boiler will be capped by federally enforceable emissions limits with compliance demonstrated by Continuous Emissions Monitoring Systems (CEMS). The old power boilers are regulated only for PM and SO2 emissions. The following table provides a comparison of the allowable PM and SO2 emissions from the existing power boilers to the new replacement power boiler.

Table 3C. Comparison of Allowable Emissions from Boilers

Emissions	Power Boiler 1	Power Boiler 2	Power Boiler 3	Total, 1-3	Power Boiler 6
PM	70.0	212.5	212.5	495.0	138.0
SO2	1848.0	1756.0	1928.0	1928.0	210.0

Conclusion

The Department also reviewed the state database (ARMS) and found the following three contemporaneous projects permitted within the last 5 years.

- Project No. 080004-014-AC authorized a temporary period to test and calibrate a new type of beta attenuation particulate monitor. The test lasted just a few days and any particulate matter emissions increases would have been quite small. It is also noted that the proposed project will result in a decrease in particulate matter emissions.
- Project No. 080004-015-AC involved the three existing power boilers. However, actual emissions from these units are already presented in the netting table for the current project.
- Project No. 080004-017-AC imposed the new Subpart MM requirements for the recovery boiler and authorized the firing of small amounts of on-specification used oil fuel generated on site. Used oil fuel would displace residual oil and there were no identifiable emissions increases.

Based on the above discussion, only the proposed digester project and the proposed boiler replacement project are contemporaneous. At the Department's request, the applicant provided the following net emissions summary of the combined projects.

Table 3D. Combined PSD Netting Analysis

Unit	Summary of Net Emissions Increases (Tons/Year)					
	CO	NOx	PM	PM_{10}[b]	SO_2	VOC[a]
Digester Project	25	0	0	0	11	27
Boiler Replacement Project	(-100 ~~297~~)	39	(-138)	(-105)	28	3.9
Total Net Change	(-75 ~~272~~)	39	(-138)	(-105)	39	31
PSD Significant Emissions Rate	100	40	25	15	40	40
Subject to PSD Review?	No	No	No	No	No	No

Notes:

a. Applicant assumed worst-case scenario for VOC emissions: digester production level of 162,000 AMDT/year prior to installation of HCE blow heat recovery system. VOC emissions will decrease before the full production level (175,000 ADMT/year) is realized because the HCE blow heat recovery system must be installed on the bleaching plant.

b. Applicant's estimation for PM_{10}.

Based on the above netting analysis that includes contemporaneous emissions increases and decreases, the project is not subject to PSD preconstruction review. The following sections provide additional details of the draft permit.

4. DIGESTER PROJECT REVIEW

Phase I – Production Capacity of 162,000 ADMT per Year

As described below, the applicant indicates that minimal additional equipment will be needed to achieve the 162,000 AMDT/yr production increase requested for this project.

Post-HCE Press Roll

The mill will add a post-HCE washer press roll. There are negligible emissions expected from the press roll because there are no chemical reactions taking place; water is being physically removed from the pulp. The press roll will result in a more uniform pulp consistency from the washer and a higher solids concentration in the HCE liquor transferred from the washer to the HCE evaporators. Although this equipment will improve overall efficiency, it is probably not a necessary addition to achieve the 162,000 ADMT per year production level. However, removing additional moisture in this step will later allow the HCE evaporators to accommodate the full requested production level of 175,000 ADMT per year. Addition of the new press roll is scheduled for 2006.

HCE Evaporators

Three new evaporator modules will be added to form a new evaporator train used to thicken the additional heat caustic extract (HCE) produced by the increase in production. Condensed water from the HCE evaporators may be used as plant process water; otherwise, it will discharge directly to the water treatment plant. Vapors that are not condensed will be directed to the existing 2-stage direct contact condenser (methanol scrubber). The condensed organics from this scrubber are discharged to the wastewater treatment plant.

Wastewater Treatment (WWT) System

VOC emissions stripped to ambient air by the aerators were calculated by the "Water9" estimation software. The emission estimate assumed "no control" from the HCE stage for increasing production to 162,000 ADMT per year.

Pulp Machine

An increase in the pulp machine drying capacity will be required. This will be accomplished by upgrading the dryer can system over which the pulp passes to dry the pulp, which includes: increasing the drying steam pressure inside the cans; installing a new head-box to increase the width of the pulp web across the machine and to improve machine sheet uniformity at higher machine speeds; and upgrading the control and water-addition systems. There are no emissions associated with pulp machine operations because there is no coating and the pulp has been purified to the point there are no remaining organics to emit.

Phase II – Increase Production Capacity to 175,000 ADMT per Year

The applicant proposes to conduct the following additional work to achieve the full requested production capacity of 175,000 ADMT per year, including the installation of a new blow heat recovery system to ensure that the project will not be PSD-significant for VOC emissions.

HCE Cell

To achieve the full requested production level of 175,000 ADMT per year, a new HCE cell will be added to handle the increased volume of pulp. A new blow heat recovery system will be installed to control emissions from this new cell as well as all existing cells. The blow heat recovery system will be installed and operational prior to increasing production beyond the 162,000 ADMT per year rate. Preliminary plans also include an additional washer for the caustic extraction stages to maintain the purity of pulp production at the full production level of 175,000 ADMT per year. This washer would be after release and capture of VOC from the HCE blow heat recovery system and would have no sulfur dioxide or chlorine emissions.

HCE Evaporator Train

Pressing additional moisture from the HCE material will allow the HCE evaporator train to accommodate the capacity increase from 162,000 to 175,000 ADMT per year. As before, condensed water from the HCE evaporators may be used as plant process water; otherwise, it will discharge directly to the water treatment plant. Vapors that are not condensed will be directed to the existing 2-stage direct contact condenser (methanol scrubber). The condensed organics from this scrubber are discharged to the wastewater treatment plant. For the full 175,000 ADMT per year production level, the emission estimates are contingent upon installing the HCE blow heat recovery system to control VOC emissions.

Blow Heat Recovery System

The mill will install a new blow heat recovery system to ensure that the project will not be PSD-significant for VOC emissions. This system will capture blow heat from one of the bleach plant stages that is the most significant source of VOC emissions. The HCE blow heat capture system will be very similar to the systems used on Kraft digesters for the recovery of heat except it will be considerably smaller and there will be no TRS gases because there is no sulfur in the pulp at this stage. The blow gas will be condensed to extract the heat and the condensate will contain VOC from the exhaust of all HCE cells. This condensate will be discharged to the biological wastewater treatment system where it will be biologically destroyed. Emissions from the HCE blow tank have been measured. The reduction in emissions that will be achieved has been estimated at greater than 74% control of HCE blow emissions, although 60% was used in estimating emission reductions.

Pulp Machine

To achieve the full requested production level of 175,000 ADMT per year, the mill plans to further increase drying capacity of the machine by increasing drying steam pressure. Depending on the effectiveness of the initial planned improvements, other pulp machine upgrades may be needed such as: final-sheet cooling; Fourdrinier wire vacuum system improvements; ventilation system upgrades; and drive system enhancements. These are all non-emitting equipment.

Wastewater Treatment (WWT) System

The amount of VOC stripped to the ambient air by the aerators was calculated by the "Water9" estimation software. For the full 175,000 ADMT per year production level, the emission estimates are contingent upon installing the HCE blow heat recovery system to control VOC emissions.

Schedule

The application indicates the following preliminary schedule for commencing construction:

Date	Activity
February 2006	Add a new HCE washer press roll
February 2007	Begin first improvements to pulp machine drying and head-box
	Add a new HCE evaporator train
February 2008	Install a new HCE blow heat recovery system to control all HCE cells
	Add a new HCE cell
	Install a new HCE washer
	Begin second improvements to pulp machine drying and speed increase
	Install a new post-HCE washer

It is noted that some of the later changes are contingent on the success of the earlier stages. New process flow diagrams are shown in Attachment A to this report.

Permit Conditions

The draft permit will include the following conditions related to this project.

- The permittee is authorized to perform the following construction and proposed work: add a new HCE washer press roll (February 2006); begin first improvements to pulp machine drying and head-box (February 2007); add a new HCE evaporator train (February 2007); install a new HCE blow heat recovery system to control all HCE cells (February 2008); add a new HCE cell (February 2008); install a new HCE washer (February 2008); begin second improvements to pulp machine drying and speed increase (February 2008); and install a new post-HCE washer (February 2008). The dates indicated represent the preliminary schedule for construction. The permittee shall obtain prior written approval for any substantial changes to the work described above and in the application for this project.
- Within fourteen (14) days of completing each of the above stages of work, the permittee shall provide a written notice of the following: type of work; date completed; minor deviations form original proposal; and a discussion of any emissions impacts.
- Upon issuance of this permit, plant production shall not exceed 162,000 ADMT per consecutive 12 months, rolling total.
- Prior to increasing plant production beyond 162,000 ADMT per year, the permittee shall install a new HCE blow heat recovery system designed to reduce VOC emissions by 60% from all HCE cells. Upon successful completion of this system, the permittee shall conduct an engineering study to determine the effectiveness of this system in capturing and reducing VOC emissions. Within 60 days of completing the engineering study, the permittee shall submit a report summarizing: the final installed design, material flow rates, emissions, emissions capture, and emissions control.
- Upon successful completion of the new HCE blow heat recovery system and submittal of the required engineering report, plant production shall not exceed 175,000 ADMT per consecutive 12 months, rolling total.
- Attached to each required Annual Operating Report, the permittee shall provide a summary of the following to the compliance authority: a summary of work performed to date; a summary of work remaining; a preliminary schedule for completing any remaining work; and the current production capacity of the mill (ADMT per year).

5. REPLACEMENT BOILER PROJECT REVIEW

Description of Boiler, Fuels and Controls

The applicant proposes to permanently shut down Power Boiler Nos. 1 – 3 and install a new bubbling bed boiler, Power Boiler No. 6. The proposed "new" boiler is a 1982 Combustion Engineering Model CE VU-40 traveling grate boiler that will be converted to a bubbling fluidized bed boiler. Initial startup of the boiler is scheduled for the end of 2006 or early 2007. It will be located adjacent to the digesters east of the mill. Once constructed and fully operational, it will be connected to the mill steam headers and the existing power boilers will cease operation and be permanently shut down. Power Boiler No. 6 and the recovery boiler will be the sole steam producers used by the mill. Eventually, the existing power boilers will be dismantled.

The design steam conditions will be 900 psig and 875° F. The maximum continuous steam production rate (24-hour average) will be 310,000 lb/hour (525 MMBtu/hour heat input). The maximum annual steam production capacity of Power Boiler No. 6 will restricted to 265,000 lb/hour based on a 12-month rolling average (450 MMBtu/hour heat input). Power Boiler No. 6 will fire the following fuels.

- Bark/Wood (SCC No. 10100901): The boiler will fire bark, wood knots, and side-hill fines recovered as process byproducts. This fuel has a heating value of approximately 9 MMBtu/ton burned (wet, as fired). Bark contains approximately 50% moisture and 0.03% sulfur by weight. Wood knots and side-hill fines contain approximately 50-60% moisture and 0.4% sulfur by weight. Based on these characteristics, the maximum boiler firing rate would be 52 tons of bark/wood per hour and, of this amount, only about 5 tons per hour would come from wood knots and side-hill fines. The maximum annual bark/wood firing would be 451,425 tons per year.
- Tire-Derived Fuel (SCC No. 10100801): Tire-derived fuel (TDF) may be fired as a supplemental fuel. This fuel has a heating value of approximately 31 MMBtu/ton burned (as fired). TDF contains less than 1% moisture and approximately 1.85% sulfur by weight. TDF would be co-fired with bark/wood at a maximum rate hourly rate of 3 tons of TDF per hour and at a maximum annual rate of 26,159 tons per year (approximately 20% of the annual average heat input rate).
- No. 6 Fuel Oil (SCC No. 10100401): No. 6 fuel oil will be fired as a supplemental fuel and may include small amounts of on-specification used oil generated on site. Fuel oil will contain a maximum of 2.5% sulfur by weight. Based on a heating value of 150 MMBtu/thousand gallons burned, the maximum hourly oil firing rate will be 1400 gallons per hour and the maximum annual firing rate will be 11,927,000 gallons per year.

During the boiler conversion, the boiler furnace will be lengthened to increase flue gas residence time and provide staged combustion to inhibit NOx formation. CO and VOC emissions are expected to be minimal at 0.25 lb/MMBtu of heat input (vendor guarantee) and 0.002 lb/MMBtu of heat input (test on similar B&W unit), respectively. The converted boiler will also include flue gas recirculation (FGR) to lower NOx emissions. The applicant expects relatively low NOx emissions from this unit after the conversion. However, the original boiler includes a selective non-catalytic reduction (SNCR) system to control NOx emissions. Due to some uncertainty of the emissions characteristics after the boiler conversion, the applicant may install this equipment after initial startup to comply with the emissions standards and caps.

An SNCR system generally consists of an ammonia tank, pumps, piping, compressed air delivery, injectors, and a control system. In the SNCR process, ammonia or urea is injected into a high-temperature region without a catalyst to reduce NOx emissions to nitrogen and water vapor. The temperature region is typically maintained above 1600° F to allow the reaction to occur; otherwise the NOx reduction will be minimal and unreacted ammonia (slip) will be emitted. Also, the exhaust temperature must not exceed 2000° F or ammonia will actually be oxidized creating additional NOx emissions. For biomass-fired boilers, SNCR can reduce NOx emissions by up to 50% or more.

Particulate matter emissions are removed from the boiler exhaust with a large setting chamber followed by an electrostatic precipitator (ESP). Large ash particles settle out in the chamber and are removed from the bottom hopper by a screw conveyor system. The four-field ESP design will include collector plates with rigid electrodes. Each field will have a dedicated transformer/rectifier (T/R) set and ash hopper. Ash will be removed by a screw conveyor system. The applicant plans to install an opacity monitor following the ESP, but before the scrubber to indicate satisfactory operation of the ESP. Although the designed system is to result in greater than 99% reduction of particulate matter emissions, the applicant requests a PM emission standard of 0.07 lb/MMBtu of heat input based on NESHAP Subpart DDDDD standards for existing units and PSD netting requirements.

An induced draft fan is located between the ESP and the wet scrubber with stack. The wet scrubber will spray approximately 4000 gpm of re-circulated alkaline scrubber water over a series of chevrons and louver-type packings to reduce SO_2 emissions. The design pressure drop across the system will be approximately 2 inches of water column. The wet scrubber will remove approximately 90% or more of SO_2 emissions under maximum operating conditions. The alkalinity of the ash formed from wood combustion is also expected to capture some SO_2 emissions. Emissions exhaust at a volumetric flow rate of 183,421 acfm and a temperature of 150° F through the wet single scrubber stack that is 10 feet in diameter and 190 feet above ground level.

Primary Applicable Requirements

NSPS Subpart Db Applicability

For new Power Boiler No. 6, the applicant proposes to modify an existing traveling grate coal-fired boiler into a bubbling bed boiler as part of this project. The existing coal-fired boiler was originally constructed in 1983 at the Stone Container Panama City Mill subject to the applicable requirements in NSPS Subpart D of 40 CFR 60 for industrial boilers. The maximum heat input rate was 540 MMBtu/hour (397 MMBtu/hour from coal and 143 MMBtu/hour from bark). In 1989, EPA promulgated NSPS Subpart Db of 40 CFR 60 for industrial boilers constructed, modified or reconstructed after June 19, 1984.

The proposed Power Boiler No. 6 will have a maximum heat input rate of 525 MMBtu/hour (315 MMBtu/hour from oil and 210 MMBtu/hour from bark) and is not considered a "new" unit as defined in NSPS Subpart Db. To be considered a "modified" boiler, the maximum emissions rate of a regulated pollutant must increase. Subpart Db regulates nitrogen oxides, particulate matter, and sulfur dioxide. The following table compares the regulated emissions as originally constructed and after conversion to a bubbling bed boiler. As shown, the Power Boiler No. 6 is not considered a modified unit subject to NSPS Subpart Db.

NSPS Subpart Db Applicability - Modification

Pollutant	Original		Converted		Modified?
	lb/MMBtu	lb/hour	lb/MMBtu	lb/hour	
NOx	0.3	162.0	0.3	157.5	No
PM	0.1	54.0	0.07	36.8	No
SO_2 – solid fossil fuel	1.2	476.4	NA	NA	NA
SO_2 – liquid fossil fuel	0.8	NA	0.8	168.0	No

A boiler is considered "reconstructed" if the cost of the replacement components exceed 50% of the fixed capital cost that would be required to construct a comparable new unit. Based on an engineering quote by the Kaeverner Corporation, it is estimated that a comparable new unit would cost approximately $40 million. Based on a vendor quote, it is estimated that the cost of replacement components to convert the existing unit to a bubbling bed boiler would be approximately $14 million. As this represents only 35% of the fixed capital costs of a comparable new unit, the boiler is not considered a reconstructed unit subject to NSPS Subpart Db.

NSPS Subpart D Applicability

The primary applicable requirements from NSPS Subpart D are summarized below.

§ 60.42 Standard for Particulate Matter

PM ≤ 0.10 lb/MMBtu derived from fossil fuel or fossil fuel and wood residue

Opacity ≤ 20% except for one 6-minute period per hour of not more than 27%

§ 60.43 Standard for Sulfur Dioxide

SO_2 ≤ 0.80 lb/MMBtu (3-hour average) derived from liquid fossil fuel or liquid fossil fuel and wood residue

§ 60.44 Standard for Nitrogen Oxides

NOx ≤ 0.30 lb per million Btu (3-hour average) derived from liquid fossil fuel or liquid fossil fuel and wood residue

§ 60.45 Emission and Fuel Monitoring

(a) Each owner or operator shall install, calibrate, maintain, and operate continuous monitoring systems for measuring the opacity of emissions, sulfur dioxide emissions, nitrogen oxides emissions, and either oxygen or carbon dioxide except as provided in paragraph (b) of this section.

(g) Excess emission and monitoring system performance reports shall be submitted to the Administrator semiannually for each six-month period in the calendar year. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period. Each excess emission and MSP report shall include the information required in Sec. 60.7(c). Periods of excess emissions and monitoring systems (MS) downtime that shall be reported are defined as follows:

(1) Opacity. Excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 20 percent opacity, except that one six-minute average per hour of up to 27 percent opacity need not be reported.

(2) Sulfur Dioxide. Excess emissions for affected facilities are defined as:

(i) Any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of sulfur dioxide as measured by a continuous monitoring system exceed the applicable standard under Sec. 60.43.

(3) Nitrogen Oxides. Excess emissions for affected facilities using a continuous monitoring system for measuring nitrogen oxides are defined as any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards under Sec. 60.44.

NESHAP Subpart DDDDD Applicability - New Power Boiler No. 6

NESHAP Subpart DDDDD applies to new, reconstructed, or existing industrial boilers. A new boiler is one that is constructed after January 13, 2003. Similar to the NSPS requirements, a boiler is considered "reconstructed" if the cost of the replacement components exceed 50% of the fixed capital cost that would be required to construct a comparable new unit. An industrial boiler that is neither new nor reconstructed is considered an existing unit.

For the subpart, "large solid fuel subcategory" includes any water-tube boiler or process heater that burns any amount of solid fuel either alone or in combination with liquid or gaseous fuels, has a rated capacity of greater than 10 MMBtu per hour heat input, and has an annual capacity factor of greater than 10 percent. Therefore, the converted Power Boiler No. 6 is subject to the applicable requirements of NSPS Subpart DDDDD as an existing, large solid fuel fired units.

The application indicates that Power Boiler No. 6 will comply with the Subpart DDDDD requirements by installing an electrostatic precipitator and an alkaline wet scrubber. The unit will be tested to demonstrate compliance with the emissions limits and work practice standards for particulate matter (in lieu of total selected metals), hydrogen chloride, and mercury. The primary applicable requirements from NESHAP Subpart AAAAA are summarized below.

Table 1 to Subpart DDDDD of Part 63. Emission Limits and Work Practice Standards

As stated in §63.7500, you must comply with the following applicable emission limits and work practice standards:

For existing large solid fuel fired boilers:

a. Particulate Matter (or Total Selected Metals) ≤ 0.07 lb per MMBtu of heat input; or (0.001 lb per MMBtu of heat input).

b. Hydrogen Chloride ≤ 0.09 lb per MMBtu of heat input.

c. Mercury ≤ 0.000009 lb per MMBtu of heat input.

Table 2 to Subpart DDDDD of Part 63. Operating Limits for Boilers and Process Heaters with Particulate Matter Emission Limits

As stated in §63.7500, you must comply with the applicable operating limits:

1. Wet scrubber control:

   a. Maintain the minimum pressure drop and liquid flow-rate at or above the operating levels established during the performance test according to §63.7530(c) and Table 7 to this subpart that demonstrated compliance with the applicable emission limit for particulate matter.

3. Electrostatic precipitator control

   a. This option is for boilers and process heaters that operate dry control systems. Existing boilers and process heaters must maintain opacity to less than or equal to 20 percent (6-minute average) except for one 6-minute period per hour of not more than 27 percent.

b. This option is only for boilers and process heaters that operate additional wet control systems. Maintain the minimum voltage and secondary current or total power input of the electrostatic precipitator at or above the operating limits established during the performance test according to §63.7530(c) and Table 7 to this subpart that demonstrated compliance with the applicable emission limit for particulate matter.

Table 4 to Subpart DDDDD of Part 63. Operating Limits for Boilers and Process Heaters with Hydrogen Chloride Limits

As stated in §63.7500, you must comply with the following applicable operating limits:

1. Wet scrubber control: Maintain the minimum scrubber effluent pH, pressure drop, and liquid flow-rate at or above the operating levels established during the performance test according to §63.7530(c) and Table 7 to this subpart that demonstrated compliance with the applicable emission limit for hydrogen chloride.

The applicant must also comply with the following applicable requirements in the associated NEHSAP tables based on the control devices and applicable emission standards and operating limits indicated above.

Table 5 Subpart DDDDD of Part 63. Performance Testing Requirements (§63.7520)

Table 6 Subpart DDDDD of Part 63. Fuel Analysis Requirements (§63.7521)

Table 7 to Subpart DDDDD of Part 63. Establishing Operating Limits (§63.7520)

Table 8 to Subpart DDDDD of Part 63. Demonstrating Continuous Compliance (§63.7540)

(Requires a Continuous Opacity Monitoring System.)

Table 9 to Subpart DDDDD of Part 63. Reporting Requirements (§63.7550)

<u>Rule 62-296.405, F.A.C. - Fossil Fuel Fired Steam Generators with a Maximum Heat Input Rate of 250 MMBtu/hour</u>

This rule establishes standards for nitrogen oxides, opacity, particulate matter, and sulfur dioxide consistent with the requirements of NSPS Subpart D.

<u>Rule 62-296.410, F.A.C. - Carbonaceous Fuel Burning Equipment</u>

This rule establishes the following standards for opacity and particulate matter.

Opacity ≤ 30% except for one 2-minute period per hour of not more than 40% as determined by DEP Method 9

PM ≤ 0.20 lb/MMBtu of heat input of carbonaceous fuel plus 0.1 lb/MMBtu of heat input from fossil fuel as determined by EPA Method 5

<u>Rule 62-212, F.A.C. – Preconstruction Review</u>

In addition to the applicable provisions identified above, the draft permit will include the following preconstruction review requirements.

- Existing Power Boilers 1 – 3 shall cease operation and be permanently shutdown prior to the commencement of commercial operation of new Power Boiler No. 6.
- The permittee shall install, calibrate, operate, and maintain continuous emissions monitoring systems for CO, NOx, SO_2, opacity, flow, and oxygen content.
- CO emissions shall not exceed ~~394.0~~ <u>591.3</u> tons during any consecutive 12 months based on CEMS data. All data (including data collected during startup, shutdown, and malfunction), shall be included in the compliance demonstration for this limit. The CO standard also serves as a surrogate for minimizing VOC emissions. {Note: Avoids PSD review pursuant to Rule 62-212.400(2)(g), F.A.C.}
- NOx emissions shall not exceed 380.0 tons during any consecutive 12 months based on CEMS data. All data (including data collected during startup, shutdown, and malfunction), shall be included in the compliance demonstration for this limit. {Note: Avoids PSD review pursuant to Rule 62-212.400(2)(g), F.A.C.}
- SO_2 emissions shall not exceed 210.0 tons during any consecutive 12 months based on CEMS data. All data

(including data collected during startup, shutdown, and malfunction), shall be included in the compliance demonstration for this limit. {Note: Avoids PSD review pursuant to Rule 62-212.400(2)(g), F.A.C.}

- As determined by EPA Method 25A stack test, VOC emissions shall not exceed 0.002 lb/MMBtu measured as carbon. [Rule 62-4.070(3), F.A.C.]
- The maximum continuous steam production rate (24-hour average) shall not exceed 310,000 pounds per hour (525 MMBtu per hour of heat input). Initial and annual compliance testing shall be conducted within 90% of this rate. If initial tests indicate that the unit cannot achieve the specified maximum steam production rate, the air construction permit shall be revised to reflect the actual installed capacity of the unit.
- The maximum annual steam production rate shall not exceed 265,000 pounds per hour (450 MMBtu per hour of heat input) based on a 12-month rolling average basis.
- After completing construction, the permittee shall conduct a test on the new boiler to determine the actual thermal efficiency of the installed boiler.
- Maintain and submit actual annual emissions for 5 years following completion of each project phase. Emissions related to demand growth that could have been accommodated prior to the project must be shown and discussed. This requirement shall be fulfilled by submittal of a report in conjunction with the required Annual Operating Report.

6. DISCUSSION OF NESHAP SUBPART S

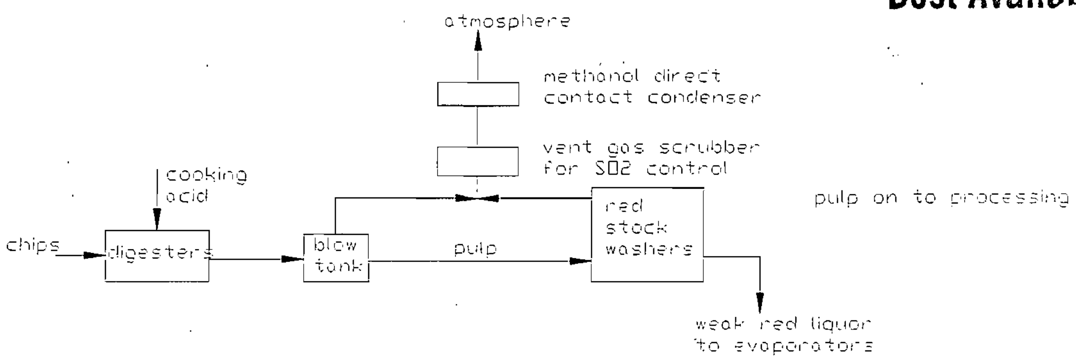
Pursuant to § 63.440(d), existing sources must be in compliance with Subpart S no later than April 16, 2001 except as provided in paragraphs (d)(1) through (d)(3). Paragraph (d)(2) applies to the existing dissolving grade bleaching system as follows, "Each dissolving-grade bleaching system at either kraft or sulfite pulping mills shall achieve compliance with the bleach plant provisions of §63.445 of this subpart *as expeditiously as practicable*, but in no event later than 3 years after the promulgation of the revised effluent limitation guidelines and standards under 40 CFR 430.14 through 430.17 and 40 CFR 430.44 through 430.47." In the August of 2005 Federal Register, EPA stated that they would not be promulgating revised effluent limitation guidelines and standards due to the limited number of plants. Instead, EPA will provide technical assistance for each project to implement appropriate waster discharge standards. Therefore, the Department will require compliance with the corresponding air emissions standards within three years of the effective date of this air construction permit to accommodate the aspect of "as expeditiously as practicable" while providing adequate notice to the permittee.

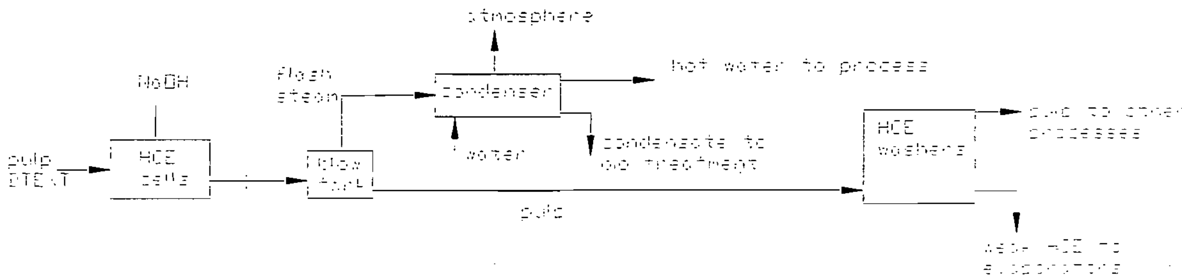
7. PRELIMINARY DETERMINATION

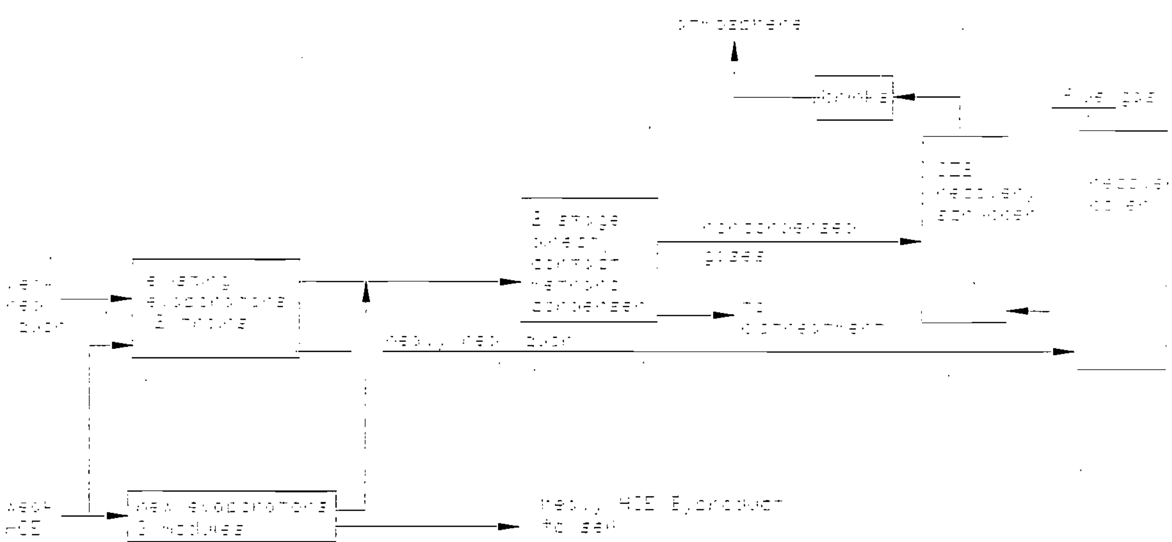
The Department makes a preliminary determination that the proposed project will comply with all applicable state and federal air pollution regulations as conditioned by the draft permit. This determination is based on a technical review of the complete application, reasonable assurances provided by the applicant, and the conditions specified in the draft permit. No air quality modeling analysis is required because the project does not result in a significant increase in emissions. Bruce Mitchell is the project engineer responsible for reviewing the application and drafting the permit. Jeff Koerner is the supervising Professional Engineer. Additional details of this analysis may be obtained by contacting the project engineer at the Department's Bureau of Air Regulation at Mail Station #5505, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400.

ATTACHMENT A

Best Available Copy







Department of Environmental Protection

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

Jeb Bush
Governor

Colleen M. Castille
Secretary

PERMITTEE:
Rayonier Performance Fibers, LLC
The Foot of Gum Street
Fernandina Beach, Florida 32035-1309

I.D. Number:	0890004
Permit Project No.:	0890004-018-AC
Date of Issue:	Month Day, 2006
Expiration Date:	March 1, 2009
County:	Nassau
Project:	Facility Modification

This permit is issued to allow an increase in the permitted throughput capacity for the facility's operations, the construction/installation of the #6 Power Boiler (PB), which replaces the three existing ones, and three evaporator bodies to thicken hot caustic extract (HCE), and to recognize the production of the No. 6 Batch Digester. The increase in production will occur in two stages and depends on the installation of some additional equipment. These changes will occur at the existing Rayonier Performance Fibers LLC's Fernandina Beach Dissolving Sulfite Pulp Mill located at The Foot of Gum Street, Fernandina Beach, Nassau County, Florida. UTM Coordinates: Zone 17; 454.7 km East; and, 3392.2 km North; Latitude: 30° 39' 44" North; and, Longitude: 81° 29' 03" West.

First, the initial increase in the facility's production will be from 153,205 to 162,000 air dried metric ton (ADMT) per consecutive 12-months, rolling total. After successful installation of a new blow heat recovery system to control VOC (volatile organic compounds) emissions from all HCE cells, production may increase to 175,000 ADMT per consecutive 12-months, rolling total. In order to achieve the increases in production, the permittee will also be authorized to perform the following construction and work: add a new HCE washer press roll; begin first improvements to pulp machine (drying and head-box); add a new HCE evaporator train; install a new HCE blow heat recovery system to control all HCE cells; add a new HCE cell; install a new HCE washer; begin second improvements to pulp machine (drying and speed increase); and, install a new post-HCE washer. The #6 PB is actually an existing used PB (obtained from another mill and built in 1983) and is being altered from a pulverized coal fired PB to a fluidized-bed wood fired PB; and, the emissions unit will replace three existing fuel-oil fired PBs, Nos. 1, 2 and 3.

STATEMENT OF BASIS: This air construction permit is issued under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawing(s), plans, and other documents, attached hereto or on file with the permitting authority, in accordance with the terms and conditions of this permit.

Referenced attachments made a part of this permit:
Title V Air Operation Permit: 0890004-011-AV
Appendix SS-1, Stack Sampling Facilities
TABLE 297.310-1, CALIBRATION SCHEDULE version dated 10/07/96
Attachment 40 CFR 60, Subpart A
FIGURE 1 - SUMMARY REPORT - GASEOUS AND OPACITY EXCESS EMISSIONS AND MONITORING SYSTEMS PERFORMANCE REPORT (40 CFR 60, July 1996)
Appendix A to 40 CFR 63, Subpart DDDDD
Appendix B to 40 CFR 63, Subpart DDDDD
Tables to 40 CFR 63, Subpart DDDDD

Michael G. Cooke, Director
Division of Air Resource Management

MGC/tlv/bm

"More Protection, Less Process"

Printed on recycled paper.

PERMITTEE:

Rayonier Performance Fibers, LLC
Foot of Gum Street
Fernandina Beach, Florida 32035-1339

Facility I.D. Number: 0890004
Permit/Project Number: 0890004-018-AC

GENERAL CONDITIONS:

1. The terms, conditions, requirements, limitations, and restrictions set forth in this permit are "Permit Conditions" and are binding and enforceable pursuant to Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of the conditions.

2. This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings, exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.

3. As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey any vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit is not a waiver of or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.

4. This permit conveys no title to land or water, does not constitute State recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title.

5. This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permitted to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department.

6. The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed and used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules.

7. The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at a reasonable time, access to the premises, where the permitted activity is located or conducted to:

   a. Have access to and copy any record that must be kept under the conditions of the permit;

   b. Inspect the facility, equipment, practices, or operations regulated or required under this permit; and

   c. Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

Reasonable time may depend on the nature of the concern being investigated.

PERMITTEE:

Rayonier Performance Fibers, LLC
Foot of Gum Street
Fernandina Beach, Florida 32035-1339

Facility I.D. Number: 0890004
Permit/Project Number: 0890004-018-AC

GENERAL CONDITIONS:

8. If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately provide the Department with the following information:

a. a description of and cause of non-compliance; and

b. the period of non-compliance, including dates and times; or, if not corrected, the anticipated time the non-compliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the non-compliance.

The permittee shall be responsible for any and all damages, which may result and may be subject to enforcement action by the Department for penalties or for revocation of this permit.

9. In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except where such use is prescribed by Sections 403.73 and 403.111, Florida Statutes. Such evidence shall only be used to the extent it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

10. The permittee agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.

11. This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 62-4.120 and 62-730.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.

12. This permit or a copy thereof shall be kept at the work site of the permitted activity.

13. This permit also constitutes:

( ) Determination of Best Available Control Technology (BACT)
( ) Determination of Prevention of Significant Deterioration (PSD)
(X) Compliance with New Source Performance Standards (NSPS)
(X) Compliance with National Emission Standards for Hazardous Air Pollutants/ Maximum Available Control Technology (MACT)

PERMITTEE:

Rayonier Performance Fibers, LLC
Foot of Gum Street
Fernandina Beach, Florida 32035-1339

Facility I.D. Number: 0890004
Permit/Project Number: 0890004-018-AC

GENERAL CONDITIONS:

14. The permittee shall comply with the following:

   a. Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.

   b. The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports required by this permit, and records of all data used to complete the application for this permit. These materials shall be retained at least three years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.

   c. Records of monitoring information shall include:

      - the date, exact place, and time of sampling or measurements;
      - the person responsible for performing the sampling or measurement;
      - the dates analyses were performed;
      - the person responsible for performing the analyses;
      - the analytical techniques or methods used; and
      - the results of such analyses.

15. When requested by the Department, the permittee shall within a reasonable time furnish any information required by law, which is needed to determine compliance with the permit. If the permittee becomes aware that relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.

PERMITTEE:

Rayonier Performance Fibers, LLC
Foot of Gum Street
Fernandina Beach, Florida 32035-1339

Facility I.D. Number: 0890004
Permit/Project Number: 0890004-018-AC

SPECIFIC CONDITIONS:

A. No. 6 Power Boiler.

E.U. ID No.	**Brief Description**
022	Bubbling Fluidized Bed No. 6 Power Boiler with a Settling Chamber followed by an ESP for PM emissions control and a Wet Alkali Scrubber for SO_2 emissions control

Emissions Unit 022 identifies the No. 6 Power Boiler, which is a converted existing power boiler. It will be firing mostly biomass (green bark, chips, knots, fines and landscape waste), tires, No. 2 fuel oil for startup, No. 6 fuel oil (max. sulfur content of 2.5%, by weight) and small amounts of facility-generated on-spec used oil (to be blended with the No. 6 fuel oil). The boiler was originally constructed in 1983 as a traveling grate coal-fired boiler.

The converted boiler will include staged combustion and flue gas recirculation (FGR) to reduce NOx emissions. Due to the planned conversion, there is some uncertainty associated with the emissions characteristics. A selective non-catalytic reduction (SNCR) system may be installed to control NOx emissions. This would generally consist of an ammonia tank, pumps, piping, compressed air delivery, injectors, and a control system.

Particulate matter emissions will be controlled with a large settling chamber followed by an electrostatic precipitator (ESP). Large ash particles settle out in the chamber and are removed from the bottom hopper by a screw conveyor system. The design includes a four-field ESP with collector plates and rigid electrodes. Each field will have a dedicated transformer/rectifier (T/R) set and ash hopper. Ash will be removed by a screw conveyor system.

Acid gases will be controlled by a wet alkaline scrubber located after the ESP and induced draft fan. The wet scrubber will spray approximately 4000 gpm of re-circulated alkaline scrubber water over a series of chevrons and louver-type packings to reduce acid gas emissions. The design pressure drop across the system will be approximately 2 inches of water column. Emissions exhaust at a volumetric flow rate of 183,421 acfm and a temperature of 150° F through the single wet scrubber stack that will be approximately 10 feet in diameter and 190 feet above ground level.

{Permitting note(s): This emissions unit is regulated under: 40 CFR 60, Subpart D; and, 40 CFR 63, Subpart DDDDD (by 09/13/07), adopted and incorporated by reference in Rule 62-204.800, F.A.C.}

The following specific conditions apply to the emissions unit listed above:

General

A.0. General.
a. Power Boilers Nos. 1, 2 and 3 shall be permanently shutdown once Power Boiler No. 6 becomes commercially operational and has been compliance tested.
[Rules 62-4.070(3) and 62-212.400(5), F.A.C.]

b. By September 13, 2007, Power Boiler No. 6 shall be in compliance with the requirements of 40 CFR 63, Subparts A and DDDDD (including Appendices A and B), which are a part of the Title V Air Operation Permit, No. 0890004-011-AV, and incorporated by reference.

[Rules 62-4.070(3) and 62-204.800, F.A.C.; and, 40 CFR 63.7495(b)]

PERMITTEE:

Rayonier Performance Fibers, LLC
Foot of Gum Street
Fernandina Beach, Florida 32035-1339

Facility I.D. Number: 0890004
Permit/Project Number: 0890004-018-AC

SPECIFIC CONDITIONS:

c. References/Acronyms.
   1. SIP: Florida's State Implementation Plan.
   2. NSPS: New Source Performance Standards.
   3. NESHAP: National Emission Standards for Hazardous Air Pollutants.
   4. AC: Air Construction Permit.
   5. PSD NSR: Prevention of Significant Deterioration New Source Review.
   6. CEMS: continuous emissions monitoring system.
   7. COMS: continuous opacity monitoring system.

d. Unless otherwise stated, the "Administrator" is the Department's "Secretary" or its designee.

e. Control Equipment.
   1. To control particulate matter, the permittee shall install a settling chamber (or equivalent) followed by a 4-field electrostatic precipitator designed to achieve at least the emissions standards specified in this permit.
   2. To control acid gases, the permittee shall install a wet alkaline scrubber designed to achieve at least the emissions standards specified in this permit.
   3. To control nitrogen oxides, the converted boiler shall be designed with staged combustion and include flue gas recirculation (FGR). In addition, the permittee is authorized to install (as necessary) a selective non-catalytic reduction system (SNCR) with ammonia injection to achieve at least the emissions standards specified in this permit.

[Rule 62-4.070(3), F.A.C.]

Operational Parameters

A.1. Permitted Capacity. The maximum heat input rates are:
   a. The maximum continuous steam production rate, 24-hour average, is 310,000 lbs/hr based on 525 MMBtu/hr heat input. Initial and annual compliance testing shall be conducted within 90% of this permitted steam rate. If the initial compliance tests cannot be performed at this level, the AC will be modified to reflect the actual installed capacity; and,
   b. The maximum annual steam production rate is 265,000 lbs/hr based on 450 MMBtu/hr heat input. This will require recordkeeping on a 12-month rolling average basis.

[Rules 62-4.070(3), 62-204.800 and 62-212.200 (PTE), F.A.C.; and, application received September 12, 2005]

A.2. Methods of Operation. This boiler may be fired with:
   a. Biomass, consisting of green bark, knots, chips, fines and landscape waste.
   b. Tire derived fuel (TDF).
   c. No. 6 fuel oil, with a maximum sulfur content of 2.5%, by weight, during startup, shutdown, or as a temporary alternate fuel during solid fuel feed upsets.
   d. Facility-generated on-specification used oil, with a maximum sulfur content of 2.5%, by weight, and shall be blended with the No. 6 fuel oil prior to firing.
   e. No. 2 fuel oil for startup.

[Application received September 12, 2005; Rule 62-710.210, F.A.C.; and, 40 CFR Part 279]

A.3. Hours of Operation. The hours of operation are not limited, i.e., 8,760 hours/year.

[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.; and, application received September 12, 2005]

PERMITTEE:

Rayonier Performance Fibers, LLC
Foot of Gum Street
Fernandina Beach, Florida 32035-1339

Facility I.D. Number: 0890004
Permit/Project Number: 0890004-018-AC

SPECIFIC CONDITIONS:

Emission Limits and Standards

*{Permitting Note: Unless otherwise specified, the averaging times for these specific conditions **A.4.** and/thru **A.11.** are based on the specified averaging time of the applicable test method.}*

A.4. Particulate Matter (PM).
a. As determined by an EPA Method 5 or 17 compliance test, PM emissions shall not exceed 0.07 lb/MMBtu heat input; nor 36.75 lbs/hr and 138.0 TPY.

[NESHAP; application received September 12, 2005; ESP design; Rule 62-4.070(3), F.A.C.; 40 CFR 63.7500(a)(1): Table 1 to Subpart DDDDD of Part 63 – Emissions Limits and Work Practice Standards: #9.a.; and, 40 CFR 63.7520(b): Table 5 to Subpart DDDDD of Part 63 – Performance Testing Requirements: #1.e.]

b. As determined by an EPA Method 5 or 5B compliance test, no owner or operator shall cause to be discharged into the atmosphere from any affected facility any gases which:
(1) Contain particulate matter in excess of 43 nanograms per joule heat input (0.10 lb per million Btu) derived from fossil fuel or fossil fuel and wood residue; nor 52.5 lbs/hr.

[NSPS; and, 40 CFR 60.42(a)(1)]

c. As determined by an EPA Method 5 compliance test, PM emissions shall not exceed 0.2 lb/MMBtu heat input of carbonaceous fuel plus 0.1 lb/MMBtu heat input of fossil fuel; nor 105 lbs/hr.

[SIP; and, Rule 62-296.410(2)(b)(2. and Chapter 62-297, F.A.C.]

A.5. Sulfur Dioxide (SO_2).
a. As determined by CEMS data, no owner or operator shall cause to be discharged into the atmosphere from any affected facility any gases which contain sulfur dioxide in excess of:
(1) 340 nanograms per joule heat input (0.80 lb per million Btu and 420 lbs/hr) derived from liquid fossil fuel or liquid fossil fuel and wood residue, and measured as any three-hour period (arithmetic average of three contiguous one-hour periods).

[NSPS; 40 CFR 60.43(a)(1); 40 CFR 60.45(g)(2); applicant requested; and, Rule 62-212.400(2)(g), F.A.C.]

b. In order to escape PSD NSR requirements and as determined by CEMS data, SO_2 emissions shall not exceed 210.0 tons per consecutive 12-month rolling total. All valid CEMS data (including startups, shutdowns and malfunctions) shall be used to determine compliance with this limit.

[Rules 62-4.160(2), 62-210.200(PTE), and 62-212.400(2)(g), F.A.C.; application received September 12, 2005; and, supplemental information received November 7, 2005]

A.6. Nitrogen Oxides (NOx).
a. As determined by CEMS data, no owner or operator shall cause to be discharged into the atmosphere from any affected facility any gases which contain nitrogen oxides, expressed as NO_2, in excess of:
(2) 129 nanograms per joule heat input (0.30 lb per million Btu and 101.20 lbs/hr), and measured as any three-hour period (arithmetic average of three contiguous one-hour periods).

[NSPS; 40 CFR 60.44(a)(2); 40 CFR 60.45(g)(3); applicant requested; and, Rule 62-212.400(2)(g), F.A.C.]

b. When different fossil fuels are burned simultaneously in any combination, the applicable standard (in ng/J) is determined by proration using the following formula:

$$PS_{NOx} = \frac{w(260)+x(86)+y(130)+z(300)}{w+x+y+z}$$

where:
PS_{NOx} = is the prorated standard for nitrogen oxides when burning different fuels simultaneously, in nanograms per joule heat input derived from all fossil fuels fired or from all fossil fuels and wood residue fired;
w = is the percentage of total heat input derived from lignite;
x = is the percentage of total heat input derived from gaseous fossil fuel;
y = is the percentage of total heat input derived from liquid fossil fuel; and,
z = is the percentage of total heat input derived from solid fossil fuel (except lignite).

[NSPS; and, 40 CFR 60.44(b)]

c. In order to escape PSD NSR requirements and as determined by CEMS data, NOx emissions shall not exceed 380.0 tons per consecutive 12-month rolling total. All valid CEMS data (including startups, shutdowns and malfunctions) shall be used to determine compliance with this limit.

[NSPS; applicant requested; 40 CFR 60.45(g); and, Rule 62-212.400(2)(g), F.A.C.]

A.7. Carbon Monoxide (CO). As determined by CEMS data, CO emissions shall not exceed 157.5 lbs/hr, 30-day rolling average; nor, 591.3 tons per consecutive 12-month rolling total. These limits are based on 0.3 lb/MMBtu heat input. All valid CEMS data (including startups, shutdowns and malfunctions) shall be used to determine compliance with this limit.

[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.; and, application and design received September 12, 2005]

A.8. Volatile Organic Compounds (VOC). As determined by an EPA Method 25A compliance test, VOC emissions shall not exceed 0.002 lb/MMBtu heat input; nor 1.05 lbs/hr and 3.94 TPY.

[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.; application received September 12, 2005; and, supplemental information received November 7, 2005]

A.9. Hydrogen Chloride. As determined by an EPA Method 26A compliance test, hydrogen chloride emissions shall not exceed 0.09 lb/MMBtu heat input. In accordance with the NESHAP, 40 CFR 63, Subpart DDDDD requirements, the permittee shall demonstrate compliance with this standard by September 13, 2007, or within 60 days of initial startup, whichever is later.

[NESHAP; 40 CFR 63.7495(b); 40 CFR 63.7500(a)(1): Table 1 to Subpart DDDDD of Part 63 – Emissions Limits and Work Practice Standards: #9.b.; and, 40 CFR 63.7520(b): Table 5 to Subpart DDDDD of Part 63 – Performance Testing Requirements: #3.e.]

SPECIFIC CONDITIONS:

A.10. Mercury. As determined by an EPA Method 29 or 101A compliance test, mercury emissions shall not exceed 0.000009 lb/MMBtu heat input. In accordance with the NESHAP, 40 CFR 63, Subpart DDDDD requirements, the permittee shall demonstrate compliance with this standard by September 13, 2007, or within 60 days of initial startup, whichever is later.

[NESHAP; 40 CFR 63.7495(b); and, 40 CFR 63.7500(a)(1): Table 1 to Subpart DDDDD of Part 63 – Emissions Limits and Work Practice Standards: #9.c.; 40 CFR 63.7520(b): Table 5 to Subpart DDDDD of Part 63 – Performance Testing Requirements: #4.e.; 40 CFR 60, Appendix A; and, 40 CFR 61, Appendix B]

A.11. Visible Emissions.
a. As determined by COMS data, no owner or operator shall cause to be discharged into the atmosphere from any affected facility any gases which:
(2) Exhibit greater than 20 percent opacity (6-minute average) except for one six-minute period per hour of not more than 27 percent opacity.

[NSPS; 40 CFR 60.42(a)(2); and, 40 CFR 60.45(g)(1)]

b. As determined by a DEP Method 9 compliance test, visible emissions shall not exceed 30 percent opacity except that a density of 40 percent opacity is permissible for not more than two minutes in any one hour.

[SIP; and, Rule 62-296.410(2)(b)1. and Chapter 62-297, F.A.C.]

A.12. Fuel Oil Sulfur Content. As determined by a lab analysis, the sulfur content of the as-fired No. 6 fuel oil shall not exceed 2.5 percent, by weight.

[Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

A.13. "On-Specification" Used Oil. The burning of "on-specification" used oil is allowed at this facility in accordance with all other conditions of this permit and the following additional conditions:
a. Only "on-specification" used oil generated by the facility shall be fired in this emissions unit. The "on-specification" used oil shall be blended with the No. 6 fuel oil prior to firing. "On-specification" used oil is defined as that which meets the 40 CFR 279 (Standards for the Management of Used Oil) specifications listed below. Used oil that does not meet all of the following specifications is considered "off-specification" oil and shall not be fired. See Specific Conditions **A.47.** and **A.48.**

CONSTITUENT / PROPERTY *	ALLOWABLE LEVEL
Arsenic	5 ppm maximum
Cadmium	2 ppm maximum
Chromium	10 ppm maximum
Lead	100 ppm maximum
Total Halogens	1000 ppm maximum
Flash Point	100 °F minimum
PCBs	less than 50 ppm

* As determined by approved methods specified in EPA Publication SW-846 (Test Methods for Evaluating Solid Waste, Physical/Chemical Methods).

[40 CFR 279.11]

SPECIFIC CONDITIONS:

b. Upon request, a certification shall be provided that the used oil (prior to blending with the No. 6 fuel oil) complies with the limits listed above, the provisions of 40 CFR 279 and 761, and shall be recorded and retained on file.

c. "On-specification" used oil may be fired as follows:

1. Any time provided the maximum concentration of PCBs is less than 2 ppm. The analysis and recordkeeping apply to each amount prior to blending even if to be blended with 90% virgin oil.
2. Only during normal operating temperature and not during startup and shutdown if the maximum concentration of $2 \leq PCB \leq 50$ ppm.

[40 CFR 279 and 761; and, Rule 62-4.070(3), F.A.C.]

<u>**Excess Emissions**</u>

{Permitting Note: The Excess Emissions Rule at Rule 62-210.700, F.A.C., cannot vary any requirement of a NSPS or NESHAP provision.}

A.14. <u>SIP Excess Emissions – Allowed</u>. Excess emissions resulting from startup, shutdown or malfunction shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration.

[Rule 62-210.700(1), F.A.C.]

A.15. <u>SIP Excess Emissions – Prohibited</u>. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown or malfunction shall be prohibited.

[Rule 62-210.700(4), F.A.C.]

A.16. <u>NSPS Excess Emissions</u>. Excess emission and monitoring system performance reports shall be submitted to the Administrator for each six-month period in the calendar year. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period. Each excess emission and MSP report shall include the information required in Sec. 60.7(c). Periods of excess emissions and monitoring systems (MS) downtime that shall be reported are defined as follows:

(1) <u>Opacity.</u> Excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 20 percent opacity, except that one six-minute average per hour of up to 27 percent opacity need not be reported.

(2) <u>Sulfur dioxide.</u> Excess emissions for affected facilities are defined as:

(i) Any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of sulfur dioxide as measured by a continuous monitoring system exceed the applicable standard under 40 CFR 60.43.

(3) <u>Nitrogen oxides.</u> Excess emissions for affected facilities using a continuous monitoring system for measuring nitrogen oxides are defined as any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards under 40 CFR 60.44.

[40 CFR 60.45(g)]

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SPECIFIC CONDITIONS:

Monitoring of Operations

A.17. Determination of Process Variables.
(a) Required Equipment. The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.
(b) Accuracy of Equipment. Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.

[Rule 62-297.310(5), F.A.C.]

A.18. Steam Monitoring. The permittee shall continuously monitor the steam production rate to demonstrate compliance with the requirements of this permit.

[Rule 62-4.070(3), F.A.C.]

A.19. Electrostatic Precipitator-Wet Scrubber Control System: PM. By September 13, 2007, the owner or operator must maintain the minimum voltage and secondary current or total power input of the electrostatic precipitator at or above the operating limits established during the performance test according to 40 CFR 63.7530(c) and Table 7, 40 CFR 63, Subpart DDDDD, that demonstrated compliance with the applicable emission limit for particulate matter. See Specific Condition **A.4.c.**

[40 CFR 63.7500(a)(2): Table 2 to Subpart DDDDD of Part 63 – Emissions Limits and Work Practice Standards: #3.b.]

A.20. Mercury. By September 13, 2007, the owner or operator must comply with the following:
a. Electrostatic Precipitator-Wet Scrubber Control System. Maintain the minimum voltage and secondary current or total power input of the electrostatic precipitator at or above the operating limits established during the performance test according to 40 CFR 63.7530(c) and Table 7, 40 CFR 63, Subpart DDDDD, that demonstrated compliance with the applicable emission limits for mercury. See Specific Condition **A.10.**
b. Fuel Analysis. Maintain the fuel type or fuel mixture such that the mercury emission rates calculated according to 40 CFR 63.7530(d)(4) is less than the applicable emission limits for mercury. See Specific Condition **A.10.**

[40 CFR 63.7500(a)(2): Table 3 to Subpart DDDDD of Part 63 – Emissions Limits and Work Practice Standards: #3.b. and #6, respectively]

A.21. Hydrogen Chloride. By September 13, 2007, the owner or operator must comply with the following:
a. Wet Scrubber Control System: Maintain the minimum scrubber effluent pH, pressure drop, and liquid flow-rate at or above the operating levels established during the performance test according to 40 CFR 63.7530(c) and Table 7, 40 CFR 63, Subpart DDDDD, that demonstrated compliance with the applicable emission limit for hydrogen chloride. See Specific Condition **A.9.**
b. Fuel Analysis: Maintain the fuel type or fuel mixture such that the hydrogen chloride emission rate calculated according to 40 CFR 63.7530(d)(3) is less than the applicable emission limit for hydrogen chloride. See Specific Condition **A.9.**

[40 CFR 63.7500(a)(2): Table 4 to Subpart DDDDD of Part 63 – Emissions Limits and Work Practice Standards: #1 and #3, respectively]

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SPECIFIC CONDITIONS:

Continuous Monitoring Requirements

A.22. Each owner or operator shall install, calibrate, maintain, and operate continuous monitoring systems for measuring the opacity of emissions, sulfur dioxide emissions, nitrogen oxides emissions, carbon monoxide emissions and oxygen, in accordance with 40 CFR 60.13, 40 CFR 60.45, and 40 CFR 60, Appendices B and F.

[40 CFR 60.13; 40 CFR 60.45(a); 40 CFR 60, Appendices B and F; Rule 62-4.070(3), F.A.C.; and, application project No. 0890004-018-AC]

A.23. The owner or operator shall install, calibrate, maintain, and operate a continuous flow monitoring system in accordance with 40 CFR 60, Performance Specification 6 of Appendix B and Procedure 1 of Appendix F.

[Application project No. 0890004-018-AC; and, 40 CFR 60, Appendices B and F]

A.24. For performance evaluations under 40 CFR 60.13(c) and calibration checks under 40 CFR 60.13(d), the following procedures shall be used:
(1) Methods 6, 7, and 3B, as applicable, shall be used for the performance evaluations of sulfur dioxide and nitrogen oxides continuous monitoring systems. Acceptable alternative methods for Methods 6, 7, and 3B are given in 40 CFR 60.46(d).
(2) Sulfur dioxide or nitric oxide, as applicable, shall be used for preparing calibration gas mixtures under Performance Specification 2 of Appendix B to 40 CFR 60.
(3) For affected facilities burning fossil fuel(s), the span value for a continuous monitoring system measuring the opacity of emissions shall be 80, 90, or 100 percent and for a continuous monitoring system measuring sulfur oxides or nitrogen oxides the span value shall be determined as follows:

[In parts per million]

Fossil fuel	Span value for sulfur dioxide	Span value for nitrogen oxides
Gas..............................	{1}	500
Liquid..............................	1,000	500
Solid..............................	1,500	1000
Combinations........................	1,000y + 1,500z	500(x+y) + 1,000z

{1}Not applicable.

where:
x = the fraction of total heat input derived from gaseous fossil fuel, and
y = the fraction of total heat input derived from liquid fossil fuel, and
z = the fraction of total heat input derived from solid fossil fuel.

(4) All span values computed under 40 CFR 60.45(c)(3) for burning combinations of fossil fuels shall be rounded to the nearest 500 ppm.
(5) For a fossil fuel-fired steam generator that simultaneously burns fossil fuel and non-fossil fuel, the span value of all continuous monitoring systems shall be subject to the Administrator's approval.

[40 CFR 60.45(c)]

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SPECIFIC CONDITIONS:

A.25. For any continuous monitoring system installed under 40 CFR 60.45(a), the following conversion procedures shall be used to convert the continuous monitoring data into units of the applicable standards (ng/J, lb/million Btu):
(1) When a continuous monitoring system for measuring oxygen is selected, the measurement of the pollutant concentration and oxygen concentration shall each be on a consistent basis (wet or dry). Alternative procedures approved by the Administrator shall be used when measurements are on a wet basis. When measurements are on a dry basis, the following conversion procedure shall be used:

$E = CF[20.9/(20.9\text{-percent } O_2)]$

where:

E, C, F, and % O_2 are determined under 40 CFR 60.45(f).

[40 CFR 60.45(e)]

A.26. The values used in the equation under 40 CFR 60.45(e)(1) is derived as follows:
(1) E = pollutant emissions, ng/J (lb/million Btu).
(2) C = pollutant concentration, ng/dscm (lb/dscf), determined by multiplying the average concentration (ppm) for each one-hour period by 4.15×10^{4} M ng/dscm per ppm (2.59×10^{-9} M lb/dscf per ppm) where M = pollutant molecular weight, g/g-mole (lb/lb-mole). M = 64.07 for sulfur dioxide and 46.01 for nitrogen oxides.
(3) % O_2, %CO_2 = oxygen or carbon dioxide volume (expressed as percent), determined with equipment specified under 40 CFR 60.45(a).
(4) F, F_c = a factor representing a ratio of the volume of dry flue gases generated to the calorific value of the fuel combusted (F), and a factor representing a ratio of the volume of carbon dioxide generated to the calorific value of the fuel combusted (F_c), respectively. Values of F and F_c are given as follows:

(iii) For liquid fossil fuels including crude, residual, and distillate oils, $F = 2.476 \times 10^{-7}$ dscm/J (9,220 dscf/million Btu) and $F_c = 0.384 \times 10^{-7}$ scm CO_2 /J (1,430 scf CO_2 /million Btu).

(v) For bark $F = 2.589 \times 10^{-7}$ dscm/J (9,640 dscf/million Btu) and $F_c = 0.500 \times 10^{-7}$ scm CO_2 /J (1,840 scf CO_2 / million Btu). For wood residue other than bark $F = 2.492 \times 10^{-7}$ dscm/J (9,280 dscf/million Btu) and Fc $= 0.494 \times 10^{-7}$ scm CO_2 /J (1,860 scf CO_2 / million Btu).

(5) The owner or operator may use the following equation to determine an F factor (dscm/J or dscf/million Btu) on a dry basis (if it is desired to calculate F on a wet basis, consult the Administrator) or F_c factor (scm CO_2 /J, or scf CO_2 /million Btu) on either basis in lieu of the F or F_c factors specified in 40 CFR 60.45(f)(4):

$$F = 10^6 \frac{227.2\,(\text{pct. H}) + 95.5\,(\text{pct. C}) + 35.6\,(\text{pct. S}) + (\text{pct. N}) - 28.7\,(\text{pct. O})}{GCV}$$

$$F_c = \frac{2.0 \times 10^{-5}\,(\text{pct. C})}{GCV \text{ (SI units)}}$$

$$F = 10^6 \frac{3.64(\%H) + 1.53(\%C) + 0.57(\%S) + 0.14(\%N) - 0.46(\%O)}{GCV \text{ (English units)}}$$

$$F_c = \frac{20.0(\%C)}{GCV \text{ (SI units)}}$$

$$Fc = \frac{321 \times 10^3(\%C)}{GCV \text{ (English units)}}$$

SPECIFIC CONDITIONS:

(i) H, C, S, N, and O are content by weight of hydrogen, carbon, sulfur, nitrogen, and oxygen (expressed as percent), respectively, as determined on the same basis as GCV by ultimate analysis of the fuel fired, using ASTM method D3178-73 (Reapproved 1979), 89, or D3176-74 or 89 (solid fuels) or computed from results using ASTM method D1137-53 or 75, D1945-64, 76, 91, or 96 or D1946-77 or 90 (Reapproved 1994) (gaseous fuels) as applicable. (These five methods are incorporated by reference-see 40 CFR 60.17.)
(ii) GCV is the gross calorific value (kJ/kg, Btu/lb) of the fuel combusted determined by the ASTM test methods D2015-77 (Reapproved 1978), 96, or D5865-98 for solid fuels and D1826-77 or 94 for gaseous fuels as applicable. (These two methods are incorporated by reference-see 40 CFR 60.17.)
(iii) For affected facilities which fire both fossil fuels and non-fossil fuels, the F or F_c value shall be subject to the Administrator's approval.

(6) For affected facilities firing combinations of fossil fuels or fossil fuels and wood residue, the F or F_c factors determined by paragraphs 40 CFR 60.45(f)(4) or (f)(5) shall be prorated in accordance with the applicable formula as follows:

$$F = \sum_{i=1}^{n} X_i F_i \quad \text{or} \quad F_c = \sum_{i=1}^{n} X_i (F_c)_i$$

where:

X_i = the fraction of total heat input derived from each type of fuel (e.g. natural gas, bituminous coal, wood residue, etc.)
F_i or $(F_c)_i$ = the applicable F or F_c factor for each fuel type determined in accordance with paragraphs (f)(4) and (f)(5) of this section.
n = the number of fuels being burned in combination.

[40 CFR 60.45(f)]

Test Methods and Procedures

A.27. In conducting the performance tests required in 40 CFR 60.8, the owner or operator shall use as reference methods and procedures the test methods in Appendix A of 40 CFR 60 or other methods and procedures as specified in 40 CFR 60.46, except as provided in 40 CFR 60.8(b). Acceptable alternative methods and procedures are given in 40 CFR 60.46(d).

[40 CFR 60.46(a)]

A.28. Boiler Thermal Efficiency. In conjunction with the initial performance tests, the permittee shall determine the installed boiler's thermal efficiency while combusting 100% wood and also 100% fuel oil.

[Rule 62-4.070(3), F.A.C.]

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SPECIFIC CONDITIONS:

A.29. The owner or operator shall determine compliance with the particulate matter, SO_2, and NO_x standards in 40 CFR 60.42, 60.43, and 60.44 as follows:
(1) The emission rate (E) of particulate matter, SO_2, or NO_x shall be computed for each run using the following equation:

$$E = C\,F_d\,(20.9)/(20.9 - \%\,O_2)$$

where:
E = emission rate of pollutant, ng/J (1b/million Btu).
C = concentration of pollutant, ng/dscm (1b/dscf).
% O_2 = oxygen concentration, percent dry basis.
F_d = factor as determined from Method 19.

[40 CFR 60.46(b)(1)]

A.30. PM Emissions.
a. For the NSPS limit, EPA Method 5 shall be used to determine the particular matter concentration (C) at affected facilities without wet flue-gas-desulfurization (FGD) systems and EPA Method 5B shall be used to determine the particulate matter concentration (C) after FGD systems. See Specific Condition **A.4.a.**
(i) The sampling time and sample volume for each run shall be at least 60 minutes and 0.85 dscm (30 dscf). The probe and filter holder heating systems in the sampling train shall be set to provide an average gas temperature of 160 ± 14 °C (320 ± 25 °F).
(ii) The emission rate correction factor, integrated or grab sampling and analysis procedure of EPA Method 3B shall be used to determine the O_2 concentration (%O_2). The O_2 sample shall be obtained simultaneously with, and at the same traverse points as, the particulate sample. If the grab sampling procedure is used, the O_2 concentration for the run shall be the arithmetic mean of the sample O_2 sample concentrations at all traverse points.
(iii) If the particulate run has more than 12 traverse points, the O_2 traverse points may be reduced to 12 provided that Method 1 is used to locate the 12 O_2 traverse points.

[40 CFR 60.46(b)(2)]

b. For the SIP limit, the test method for PM shall be EPA Method 5, incorporated and adopted by reference in Chapter 62-297, F.A.C. See Specific Condition **A.4.b.**
c. Test procedures shall meet all applicable requirements of Chapter 62-297, F.A.C.

[Rules 62-296.410(3)(b) & (c), F.A.C.]

d. A compliance test shall be conducted initially and once each federal fiscal year.

[Rule 62-297.310(7)(a)4., F.A.C.]

A.31. Sulfur Dioxide Emissions.

a. EPA Method 6 shall be used to determine the SO_2 concentration.

(i) The sampling site shall be the same as that selected for the particulate sample. The sampling location in the duct shall be at the centroid of the cross section or at a point no closer to the walls than 1 m (3.28 ft). The sampling time and sample volume for each sample run shall be at least 20 minutes and 0.020 dscm (0.71 dscf). Two samples shall be taken during a 1-hour period, with each sample taken within a 30-minute interval.

(ii) The emission rate correction factor, integrated sampling and analysis procedure of EPA Method 3B shall be used to determine the O_2 concentration ($\%O_2$). The O_2 sample shall be taken simultaneously with, and at the same point as, the SO_2 sample. The SO_2 emission rate shall be computed for each pair of SO_2 and O_2 samples. The SO_2 emission rate (E) for each run shall be the arithmetic mean of the results of the two pairs of samples.

[40 CFR 60.46(b)(4)]

b. A compliance test shall be conducted initially and in accordance with 40 CFR 60.8. Continuous compliance shall be demonstrated by the required emissions monitoring system.

[40 CFR 60.8; and, Rule 62-297.310(7)(a)4., F.A.C.]

A.32. Nitrogen Oxides Emissions.

a. EPA Method 7 shall be used to determine the NO_X concentration.

(i) The sampling site and location shall be the same as for the SO_2 sample. Each run shall consist of four grab samples, with each sample taken at about 15-minute intervals.

(ii) For each NO_X sample, the emission rate correction factor, grab sampling and analysis procedure of EPA Method 3B shall be used to determine the O_2 concentration ($\%O_2$). The sample shall be taken simultaneously with, and at the same point as, the NO_X sample.

(iii) The NO_X emission rate shall be computed for each pair of NO_X and O_2 samples. The NO_X emission rate (E) for each run shall be the arithmetic mean of the results of the four pairs of samples.

[40 CFR 60.46(b)(5)]

b. A compliance test shall be conducted initially and in accordance with 40 CFR 60.8. Continuous compliance shall be demonstrated by the required emissions monitoring system.

[40 CFR 60.8; and, Rule 62-297.310(7)(a)4., F.A.C.]

A.33. CO Emissions. The test method for carbon monoxide emissions shall be EPA Method 10, incorporated in Chapter 62-297, F.A.C. A compliance test shall be conducted initially and in accordance with 40 CFR 60.8. Continuous compliance shall be demonstrated by the required emissions monitoring system.

[40 CFR 60.8; and, Rules 62-297.401 and 62-297.310(7)(a)4., F.A.C.]

A.34. VOC Emissions.

a. The test method for VOC emissions shall be EPA Method 25A, incorporated in Chapter 62-297, F.A.C. A compliance test shall be conducted initially and in accordance with 40 CFR 60.8.; and, once every five years for renewal.

[40 CFR 60.8; and, Rules 62-297.401 and 62-297.310(7)(a)4., F.A.C.]

SPECIFIC CONDITIONS:

A.35. Visible Emissions.
a. For the NSPS limit, EPA Method 9 and the procedures in 40 CFR 60.11 shall be used to determine opacity. Compliance shall be demonstrated by COMS. See Specific Condition **A.11.a.**

[40 CFR 60.11; and, 40 CFR 60.46(b)(3)]

b. For the SIP limit, the test method for visible emissions shall be DEP Method, incorporated in Chapter 62-297, F.A.C. See Specific Conditions **A.11.b.** and **A.36.**
c. Test procedures shall meet all applicable requirements of Chapter 62-297, F.A.C.

[Rules 62-296.410(3)(a) & (c), F.A.C.]

d. A compliance test shall be conducted initially and in accordance with 40 CFR 60.8. Continuous compliance shall be demonstrated by COMS.

[40 CFR 60.8; and, Rule 62-297.310(7)(a)4., F.A.C.]

A.36. DEP Method 9. The provisions of EPA Method 9 (40 CFR 60, Appendix A) are adopted by reference with the following exceptions:
1. EPA Method 9, Section 2.4, Recording Observations. Opacity observations shall be made and recorded by a certified observer at sequential fifteen second intervals during the required period of observation.
2. EPA Method 9, Section 2.5, Data Reduction. For a set of observations to be acceptable, the observer shall have made and recorded, or verified the recording of, at least 90 percent of the possible individual observations during the required observation period. For single-valued opacity standards (e.g., 20 percent opacity), the test result shall be the highest valid six-minute average for the set of observations taken. For multiple-valued opacity standards (e.g., 20 percent opacity, except that an opacity of 40 percent is permissible for not more than two minutes per hour) opacity shall be computed as follows:

a. For the basic part of the standard (i.e., 20 percent opacity) the opacity shall be determined as specified above for a single-valued opacity standard.

b. For the short-term average part of the standard, opacity shall be the highest valid short-term average (i.e., two-minute, three-minute average) for the set of observations taken.

In order to be valid, any required average (i.e., a six-minute or two-minute average) shall be based on all of the valid observations in the sequential subset of observations selected, and the selected subset shall contain at least 90 percent of the observations possible for the required averaging time. Each required average shall be calculated by summing the opacity value of each of the valid observations in the appropriate subset, dividing this sum by the number of valid observations in the subset, and rounding the result to the nearest whole number. The number of missing observations in the subset shall be indicated in parenthesis after the subset average value.

[Rule 62-297.401, F.A.C.]

PERMITTEE:

Rayonier Performance Fibers, LLC
Foot of Gum Street
Fernandina Beach, Florida 32035-1339

Facility I.D. Number: 0890004
Permit/Project Number: 0890004-018-AC

SPECIFIC CONDITIONS:

A.37. Fuel Analyses. For Power Boiler No. 6, the following fuel sampling and analysis protocol shall be used:
a. Determine and record the as-fired fuel sulfur content, percent by weight, for liquid fuels using either ASTM D2622-92, ASTM D4294-90, both ASTM D4057-88 and ASTM D129-91, or the latest edition, by analyzing a representative sample of the blended fuel oil following each fuel delivery.
b. Record hourly fuel totalizer readings with calculated hourly feed rates for each fuel fired, the ratio of fuels fired, the density of each fuel, and the percent sulfur content, by weight, of each fuel.
c. The analyses of the No. 6 fuel oil, as received from the supplier in a bill of lading, shall include the following:
1. Density (ASTM D 1298-80 or the latest edition).
2. Calorific heat value in Btu per pound (ASTM D 240-76 or the latest edition).
3. Sulfur content, by weight (ASTM D2622-92, ASTM D4294-90, both ASTM D4057-88 and ASTM D129-91, or the latest edition).
d. On a quarterly basis, an analyses of the wood fuel shall include the following:
1. Calorific heat value in Btu per pound (ASTM D2015-77, or the latest edition).
2. Moisture content (ASTM D2016-74, 83, or the latest edition).
3. Sulfur content, by weight (Test Methods for Evaluating Solid Waste, Physical/Chemical Methods: EPA Publication SW-846 Third Edition (November 1986), or the latest edition).

[40 CFR 60, Subpart A]

A.38. Required Number of Test Runs. For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured provided, however, that three complete and separate determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the owner or operator, and a valid third run cannot be obtained within the five day period allowed for the test, the Secretary or his or her designee may accept the results of the two complete runs as proof of compliance, provided that the arithmetic mean of the results of the two complete runs is at least 20 percent below the allowable emission limiting standards.

[Rule 62-297.310(1), F.A.C.]

A.39. Operating Rate During Testing.
a. Testing of emissions shall be conducted with each emissions unit operation at permitted capacity, which is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impracticable to test at permitted capacity, an emissions unit may be tested at less than the minimum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test load until a new test is conducted. Once the emissions unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity.

[Rules 62-297.310(2) & (2)(b), F.A.C.]

b. If the new emissions unit is unable to achieve the designed permitted capacity (at least 90%) for the initial tests, then this permit will be revised to reflect the true installed capacity.

[Rule 62-4.070(3), F.A.C.]

SPECIFIC CONDITIONS:

A.40. Calculation of Emission Rate. The indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the separate test runs unless otherwise specified in a particular test method or applicable rule.

[Rule 62-297.310(3), F.A.C.]

A.41. Applicable Test Procedures.

(a) Required Sampling Time.

1. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes.

2. Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:

c. The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.

(b) Minimum Sample Volume. Unless otherwise specified in the applicable rule, the minimum sample volume per run shall be 25 dry standard cubic feet.

(c) Required Flow Rate Range. For EPA Method 5 particulate sampling, acid mist/sulfur dioxide, and fluoride sampling which uses Greenburg Smith type impingers, the sampling nozzle and sampling time shall be selected such that the average sampling rate will be between 0.5 and 1.0 actual cubic feet per minute, and the required minimum sampling volume will be obtained.

(d) Calibration of Sampling Equipment. Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1 (attached).

(e) Allowed Modification to EPA Method 5. When EPA Method 5 is required, the following modification is allowed: the heated filter may be separated from the impingers by a flexible tube.

[Rule 62-297.310(4), F.A.C.]

A.42. Required Stack Sampling Facilities. When a mass emissions stack test is required, the permittee shall comply with the requirements contained in Appendix SS-1, Stack Sampling Facilities, attached to this permit.

[Rule 62-297.310(6), F.A.C.]

SPECIFIC CONDITIONS:

A.43. Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.

(a) General Compliance Testing.

2. For excess emission limitations for particulate matter specified in Rule 62-210.700, F.A.C., a compliance test shall be conducted annually while the emissions unit is operating under soot blowing conditions in each federal fiscal year during which soot blowing is part of normal emissions unit operation, except that such test shall not be required in any federal fiscal year in which a fossil fuel steam generator does not burn liquid fuel for more than 400 hours other than during startup.

3. The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision. In renewing an air operation permit pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal:

   a. Did not operate; or
   b. In the case of a fuel burning emissions unit, burned liquid fuel for a total of no more than 400 hours.

4. During each federal fiscal year (October 1 – September 30), unless otherwise specified by rule, order, or permit, the owner or operator of each emissions unit shall have a formal compliance test conducted for:

   a. Visible emissions, if there is an applicable standard;
   b. Each of the following pollutants, if there is an applicable standard, and if the emissions unit emits or has the potential to emit: 5 tons per year or more of lead or lead compounds measured as elemental lead; 30 tons per year or more of acrylonitrile; or 100 tons per year or more of any other regulated air pollutant; and
   c. Each NESHAP pollutant, if there is an applicable emission standard.

5. An annual compliance test for particulate matter emissions shall not be required for any fuel burning emissions unit that, in a federal fiscal year, does not burn liquid fuel, other than during startup, for a total of more than 400 hours.

9. The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.

(b) Special Compliance Tests. When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it may require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department.

(c) Waiver of Compliance Test Requirements. If the owner or operator of an emissions unit that is subject to a compliance test requirement demonstrates to the Department, pursuant to the procedure established in Rule 62-297.620, F.A.C., that the compliance of the emissions unit with an applicable weight emission limiting standard can be adequately determined by means other than the designated test procedure, such as specifying a surrogate standard of no visible emissions for particulate matter sources equipped with a bag house or specifying a fuel analysis for sulfur dioxide emissions, the Department shall waive the compliance test requirements for such emissions units and order that the alternate means of determining compliance be used, provided, however, the provisions of Rule 62-297.310(7)(b), F.A.C., shall apply.

[Rule 62-297.310(7), F.A.C.; and, SIP approved]

SPECIFIC CONDITIONS:

Recordkeeping and Reporting Requirements

A.44. Notification.
a. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department's NED office in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department's NED.

[Rule 62-210.700(6), F.A.C.]

b. If CEMS or COMS data indicates non-compliance, the permittee shall notify the Department's NED office within one working day of such determination.

[Rule 62-4.070(3), F.A.C.]

A.45. Plant Operation - Problems. If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the owner or operator shall notify the Department as soon as possible, but at least within one (1) working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; the steps being taken to correct the problem and prevent future recurrence; and where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit and the regulations.

[Rule 62-4.130, F.A.C.]

A.46. Test Reports.
(a) The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department's NED on the results of each such test.
(b) The required test report shall be filed with the Department's NED as soon as practical but no later than 45 days after the last sampling run of each test is completed.
(c) The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the Department's NED to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information:

1. The type, location, and designation of the emissions unit tested.
2. The facility at which the emissions unit is located.
3. The owner or operator of the emissions unit.
4. The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.
5. The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.
6. The type of air pollution control devices installed on the emissions unit, their general condition, their normal operating parameters (pressure drops, total operating current and GPM scrubber water), and their operating parameters during each test run.
7. A sketch of the duct within 8 stack diameters upstream and 2 stack diameters downstream of the sampling ports, including the distance to any upstream and downstream bends or other flow disturbances.
8. The date, starting time and duration of each sampling run.
9. The test procedures used, including any alternative procedures authorized pursuant to Rule 62-297.620, F.A.C. Where optional procedures are authorized in this chapter, indicate which option was used.
10. The number of points sampled and configuration and location of the sampling plane.
11. For each sampling point for each run, the dry gas meter reading, velocity head, pressure drop across the stack, temperatures, average meter temperatures and sample time per point.

SPECIFIC CONDITIONS:

12. The type, manufacturer and configuration of the sampling equipment used.
13. Data related to the required calibration of the test equipment.
14. Data on the identification, processing and weights of all filters used.
15. Data on the types and amounts of any chemical solutions used.
16. Data on the amount of pollutant collected from each sampling probe, the filters, and the impingers, are reported separately for the compliance test.
17. The names of individuals who furnished the process variable data, conducted the test, analyzed the samples and prepared the report.
18. All measured and calculated data required to be determined by each applicable test procedure for each run.
19. The detailed calculations for one run that relate the collected data to the calculated emission rate.
20. The applicable emission standard, and the resulting maximum allowable emission rate for the emissions unit, plus the test result in the same form and unit of measure.
21. A certification that, to the knowledge of the owner or his authorized agent, all data submitted are true and correct. When a compliance test is conducted for the Department or its agent, the person who conducts the test shall provide the certification with respect to the test procedures used. The owner or his authorized agent shall certify that all data required and provided to the person conducting the test are true and correct to his knowledge.

[Rules 62-213.440 and 62-297.310(8), F.A.C.]

A.47. Monthly records shall be kept of the quantity of "on-specification" used oil fired in these emissions units. The above records shall be maintained in a form suitable for inspection, retained for a minimum of five years, and be made available upon request. See Specific Conditions **A.13.** and **A.48.**

[Rule 62-213.440(1)(b)2.b., F.A.C.; and, 40 CFR 279.61 and 761.20(e)]

A.48. The permittee shall include in the "Annual Operating Report for Air Pollutant Emitting Facility" a summary of the "on-specification" used oil fired in the No. 6 Power Boiler during the calendar year. See Specific Conditions **A.13.** and **A.47.**

[Rule 62-213.440(1)(b)2.b., F.A.C.]

A.49. NSPS Excess Emission and Monitoring System Performance Reports. Excess emission and monitoring system performance reports shall be submitted to the Administrator for each six-month period in the calendar year. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period. Each excess emission and MSP report shall include the information required in Sec. 60.7(c). Periods of excess emissions and monitoring systems (MS) downtime that shall be reported are defined as follows:

(1) Opacity. Excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 20 percent opacity, except that one six-minute average per hour of up to 27 percent opacity need not be reported.

(2) Sulfur dioxide. Excess emissions for affected facilities are defined as:

(i) Any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of sulfur dioxide as measured by a continuous monitoring system exceed the applicable standard established under 40 CFR 60.43. See Specific Condition **A.5.a.(1).**

(3) Nitrogen oxides. Excess emissions for affected facilities using a continuous monitoring system for measuring nitrogen oxides are defined as any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards under 40 CFR 60.44. See Specific Condition **A.6.a.(2).**

[40 CFR 60.45(g)(1), (2) & (3)]

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Rayonier Performance Fibers, LLC
Foot of Gum Street
Fernandina Beach, Florida 32035-1339

Facility I.D. Number: 0890004
Permit/Project Number: 0890004-018-AC

SPECIFIC CONDITIONS:

A.50. Within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of such facility and at such other times as may be required by the Administrator under section 114 of the Act, the owner or operator of such facility shall conduct performance test(s) and furnish the Administrator a written report of the results of such performance test(s).

[40 CFR 60.8(a)]

A.51. Performance tests shall be conducted and data reduced in accordance with the test methods and procedures contained in each applicable subpart unless the Administrator:
(1) Specifies or approves, in specific cases, the use of a reference method with minor changes in methodology;
(2) Approves the use of an equivalent method;
(3) Approves the use of an alternative method the results of which he has determined to be adequate for indicating whether a specific source is in compliance;
(4) Waives the requirement for performance tests because the owner or operator of a source has demonstrated by other means to the Administrator's satisfaction that the affected facility is in compliance with the standard; or
(5) Approves shorter sampling times and smaller sample volumes when necessitated by process variables or other factors. Nothing in 40 CFR 60.8 shall be construed to abrogate the Administrator's authority to require testing under section 114 of the Act.

[40 CFR 60.8(b)(1), (2), (3), (4) & (5)]

A.52. Performance tests shall be conducted under such conditions as the Administrator shall specify to the plant operator based on representative performance of the affected facility. The owner or operator shall make available to the Administrator such records as may be necessary to determine the conditions of the performance tests. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a performance test nor shall emissions in excess of the level of the applicable emission limit during periods of startup, shutdown, and malfunction be considered a violation of the applicable emission limit unless otherwise specified in the applicable standard.

[40 CFR 60.8(c)]

A.53. The owner or operator of an affected facility shall provide the Administrator at least 30 days prior notice of any performance test, except as specified under other subparts, to afford the Administrator the opportunity to have an observer present. If after 30 days notice for an initially scheduled performance test, there is a delay (due to operational problems , etc) in conducting the scheduled performance test, the owner or operator of an affected facility shall notify the administrator (or delegated State or local agency) as soon as possible of any delay in the original test date, either by providing at least 7 days prior notice of the rescheduled date of the performance test, or by arranging a rescheduled date with the Administrator (or delegated State or local agency) by mutual agreement.

[40 CFR 60.8(d)]

SPECIFIC CONDITIONS:

A.54. The owner or operator of an affected facility shall provide, or cause to be provided, performance testing facilities as follows:

(1) Sampling ports adequate for test methods applicable to such facility. This includes
 (i) constructing the air pollution control system such that volumetric flow rates and pollutant emission rates can be accurately determined by applicable test methods and procedures and
 (ii) providing a stack or duct free of cyclonic flow during performance tests, as demonstrated by applicable test methods and procedures.
(2) Safe sampling platform(s).
(3) Safe access to sampling platform(s).
(4) Utilities for sampling and testing equipment.

[40 CFR 60.8(e)(1), (2), (3) & (4)]

A.55. Unless otherwise specified in the applicable subpart, each performance test shall consist of three separate runs using the applicable test method. Each run shall be conducted for the time and under the conditions specified in the applicable standard. For the purpose of determining compliance with an applicable standard, the arithmetic means of results of the three runs shall apply. In the event that a sample is accidentally lost or conditions occur in which one of the three runs must be discontinued because of forced shutdown, failure of an irreplaceable portion of the sample train, extreme meteorological conditions, or other circumstances, beyond the owner or operator's control, compliance may, upon the Administrator's approval, be determined using the arithmetic mean of the results of the two other runs.

[40 CFR 60.8(f)]

B. <u>No. 6 Batch Digester</u>.

B.1. The new No. 6 batch digester is in operation and included in with the "batch digesters" under Emissions Unit 005, Vent Gas Scrubber and Direct Contact Condenser", and is subject to the terms and conditions established for this emissions unit in Title V permit, No. 0890004-011-AV, specifically in Subsection G., which is incorporated by reference.

{Emission Unit 005 includes the vent gas scrubber (wet scrubber), which controls emissions from numerous vents from the cooking acid plant, the red stock washers, the unwashed stock tank, the spent sulfite liquor storage tanks, the spent sulfite liquor washer area, the digesters, and the blow pits. The scrubber is a packed bed containing 10 feet of packing consisting of two packed sections. The lower section is designed for sulfur dioxide emissions control via gas absorption using alkaline scrubbing media (soda ash, sodium hydroxide, etc.). The spent scrubber media is bled first to other closed sources to make maximum use of the alkali to remove sulfur dioxide, and then to sewer via closed piping to number 1 Pump Station. The sulfur dioxide concentration in the stack is continuously measured with a CMS.

The upper packed section of the vent gas scrubber is designed to condense methanol from the gas stream by direct contact with fresh well water, i.e. the Direct Contact Condenser. This is a once through process. The condensed methanol held in the water is sent to the biological effluent treatment system for treatment in order to comply with the requirements of 40 CFR 63, Subpart S.}

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SPECIFIC CONDITIONS:

C. Multiple Effect Evaporators (3 bodies).

C.1. The permittee is authorized to install three (3) new Multiple Effect Evaporators (MEEs) bodies, which are refurbished existing units. They will form a new train to be used to increase the solids concentration of weak HCE, a byproduct stream from the manufacturing process that can be used at Kraft mills as a sodium source. All of the MEEs will vent through a common condenser used to collect methanol and then vented to the atmosphere via the sulfur dioxide recovery scrubber for the recovery boiler. The new bodies will be lumped in with the two sets of MEEs and will now be described as "three" sets of MEEs under Emissions Unit 021, and subject to the terms and conditions established for this emissions unit in Title V permit, No. 0890004-011-AV, specifically in Subsection G., which is incorporated by reference.

{Emissions Unit 021 includes the Evaporator Vents Methanol Condenser System. The steam that is used to eject the vent gases from the two sets of multiple effect evaporators along with the evaporator vent gases themselves, are piped to a pre-condenser which condenses the steam followed by the main condenser which condenses the methanol. The water used to condense the steam and methanol is reclaimed from the biological effluent treatment system after the methanol has been digested.

The condensate from the pre-condenser and the main condenser are sewered to the biological effluent treatment system via the Number 3 Pump Station for compliance with the 40 CFR 63, Subpart S requirements.

The non-condensable gases from the main condenser are sent to the multi-stage wet scrubber/Brinks Demister at the Recovery boiler (Emissions Unit No. 006).}

D. Facility.

D.1. Capacity.
a. Except as provided below, the facility's production shall not exceed 162,000 air dried metric tons (ADMT) per consecutive 12-months, rolling total.
b. Upon successful installation and submittal of the engineering report of the HCE blow heat recovery system to control VOC emissions from all of the HCE cells, the facility's production shall not exceed 175,000 ADMT per consecutive 12-months, rolling total.

[Rules 62-4.070(3), 210.200(PTE) and 62-212.400(5), F.A.C.]

D.2. The application indicates the following preliminary schedule for commencing construction:

Date	Activity
February 2006	Add a new HCE washer press roll
February 2007	Begin first improvements to pulp machine (drying and head-box)
	Add a new HCE evaporator train
February 2008	Install a new HCE blow heat recovery system to control all HCE cells
	Add a new HCE cell
	Install a new HCE washer
	Begin second improvements to pulp machine (drying and speed increase)
	Install a new post-HCE washer

* It is noted that some of the later changes are contingent on the success of the earlier stages.

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SPECIFIC CONDITIONS:

D.3. The permittee is authorized to perform the following construction and work:

a. add a new HCE washer press roll;
b. begin first improvements to pulp machine (drying and head-box);
c. add a new HCE evaporator train; install a new HCE blow heat recovery system to control all HCE cells;
d. add a new HCE cell;
e. install a new HCE washer; begin second improvements to pulp machine (drying and speed increase); and,
f. install a new post-HCE washer.

The permittee shall obtain prior written approval for any substantial changes to the work described above and in the application for this project.

D.4. Within fourteen (14) days of completing each of the above stages of work, the permittee shall provide a written notice of the following:

a. type of work;
b. date completed;
c. deviations form original proposal; and,
d. a discussion of any emissions impacts.

D.5. Attached to each required Annual Operating Report, the permittee shall provide a summary of the following to the compliance authority:

a. a summary of work performed to date;
b. a summary of work remaining;
c. a preliminary schedule for completing any remaining work; and,
d. the current production capacity of the mill (ADMT per year).

D.6. Performance tests.
a. Prior to increasing plant production beyond 162,000 ADMT per year, the permittee shall install a new HCE blow heat recovery system designed to reduce VOC emissions by 60% from all HCE cells. Upon successful completion of this system, the permittee shall conduct an engineering study to determine the effectiveness of this system in capturing and reducing VOC emissions to achieve designed efficiency . A test protocol shall be submitted to the Department for review and approval prior to commencing the engineering study. Within 60 days of completing the engineering study, the permittee shall submit a report summarizing: the final installed design, material flow rates, emissions, emissions capture, emissions control, and any necessary adjustments.

[Rule 62-4.070(3), F.A.C.]

E. Miscellaneous.

E.1. Report of Actual Emissions. The permittee shall maintain and submit actual annual emissions for a period of 5 years following completion of each project phase. Emissions related to demand growth that could have been accommodated prior to the project must be shown and discussed. This requirement shall be fulfilled by submittal of a report in conjunction with the required Annual Operating Report.

[Rule 62-4.070(3) and 62-212.400(5), F.A.C.]

E.2. Testing While Burning TDF. A one-time test shall be conducted while burning the maximum percentage of TDF expected using EPA Method 29 pursuant to 40 CFR 60, Appendix A, and Chapter 62-297, F.A.C.

[Rule 62-4.070(3) and Chapter 62-297, F.A.C.; and, 40 CFR 60, Appendix A]

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SPECIFIC CONDITIONS:

F. <u>Bleach Plant</u>.

F.1. The dissolving-grade bleaching system shall achieve compliance with the bleach plant provisions of 40 CFR 63.445 *as expeditiously as practicable*, but in no event later than 4 years from the issuance of this air construction permit.

[40 CFR 63.440(d)(2) and 63.445]

Attachment "40 CFR 60, Subpart A"

General Provisions

40 CFR 60.1 Applicability.

(a) Except as provided in 40 CFR 60 subparts B and C, the provisions of this part apply to the owner or operator of any stationary source which contains an affected facility, the construction or modification of which is commenced after the date of publication in this part of any standard (or, if earlier, the date of publication of any proposed standard) applicable to that facility.
(b) Any new or revised standard of performance promulgated pursuant to section 111(b) of the Act shall apply to the owner or operator of any stationary source which contains an affected facility, the construction or modification of which is commenced
after the date of publication in this part of such new or revised standard (or, if earlier, the date of publication of any proposed standard) applicable to that facility.
(c) In addition to complying with the provisions of this part, the owner or operator of an affected facility may be required to obtain an operating permit issued to stationary sources by an authorized State air pollution controlagency or by the Administrator of the U.S. Environmental Protection Agency (EPA) pursuant to Title V of the Clean Air Act (CAA) as amended November 15, 1990 (42 U.S.C. 7661).
[Rule 62-204.800, F.A.C.; and, 40 CFR 60.1(a), (b) and (c)]

40 CFR 60.2 Definitions.

(a) *Administrator* means the Administrator of the Environmental Protection Agency or the Secretary or the Secretary's designee.
[Rule 62-204.800(7)(a), F.A.C.; and, 40 CFR 60.2]

40 CFR 60.7 Notification and record keeping.

(a) The owner or operator subject to the provisions of this part shall furnish the Administrator written notification as follows:

(1) A notification of the <u>date construction</u> (or reconstruction as defined under 40 CFR 60.15) of an affected facility is <u>commenced</u> postmarked no later than 30 days after such date. This requirement shall not apply in the case of mass-produced facilities which are purchased in completed form.
(2) A notification of the <u>anticipated date of initial startup</u> of an affected facility postmarked not more than 60 days nor less than 30 days prior to such date.
(3) A notification of the <u>actual date of initial startup</u> of an affected facility postmarked within 15 days after such date.
(4) A notification of <u>any physical or operational change</u> to an existing facility which may increase the emission rate of any air pollutant to which a standard applies, unless that change is specifically exempted under an applicable subpart or in 40 CFR 60.14(e). This notice shall be postmarked 60 days or as soon as practicable before the change is commenced and shall include information describing the precise nature of the change, present and proposed emission control systems, productive capacity of the facility before and after the change, and the expected completion date of the change. The Administrator may request additional relevant information subsequent to this notice.
(5) A notification of the date upon which demonstration of the continuous monitoring system performance commences in accordance with 40 CFR 60.13(c). Notification shall be postmarked not less than 30 days prior to such date.

(6) A notification of the anticipated date for conducting the opacity observations required by 40 CFR 60.11(e)(1) of this part. The notification shall also include, if appropriate, a request for the Administrator to provide a visible emissions reader during a performance test. The notification shall be postmarked not less than 30 days prior to such date.

(7) A notification that continuous opacity monitoring system data results will be used to determine compliance with the applicable opacity standard during a performance test required by 40 CFR 60.8 in lieu of Method 9 observation data as allowed by 40 CFR 60.11(e)(5) of 40 CFR 60. This notification shall be postmarked not less than 30 days prior to the date of the performance test.

(b) The owner or operator subject to the provisions of this part shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of an affected facility; any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or monitoring device is inoperative.

(c) The owner or operator required to install a continuous monitoring system (CMS) or monitoring device shall submit an excess emissions and monitoring systems performance report (excess emissions are defined in applicable subparts) and/or a summary report form (see 40 CFR 60.7(d) to the Administrator semiannually, except when: more frequent reporting is specifically required by an applicable subpart; or the CMS data are to be used directly for compliance determination, in which case quarterly reports shall be submitted; or the Administrator, on a case-by-case basis, determines that more frequent reporting is necessary
to accurately assess the compliance status of the source. All reports shall be postmarked by the 30th day following the end of each calendar half (or quarter, as appropriate). Written reports of excess emissions shall include the following information:

(1) The magnitude of excess emissions computed in accordance with 40 CFR 60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the reporting period.

(2) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken or preventative measures adopted.

(3) The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.

(4) When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report.

(d) The summary report form shall contain the information and be in the format shown in Figure 1 unless otherwise specified by the Administrator. One summary report form shall be submitted for each pollutant monitored at each affected facility.

(1) If the total duration of excess emissions for the reporting period is less than 1 percent of the total operating time for the reporting period and CMS downtime for the reporting period is less than 5 percent of the total operating time for the reporting period, only the summary report form shall be submitted and the excess emission report described in 40 CFR 60.7(c) need not be submitted unless requested by the Administrator.

(2) If the total duration of excess emissions for the reporting period is 1 percent or greater of the total operating time for the reporting period or the total CMS downtime for the reporting period is 5 percent or greater of the total operating time for the reporting period, the summary report form and the excess emission report described in 40 CFR 60.7(c) shall both be submitted.

[See Attached Figure 1-Summary Report-Gaseous and Opacity Excess Emission and Monitoring System Performance]

(e) The owner or operator subject to the provisions of this part shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by this part recorded in a permanent form suitable for inspection. The file shall be retained for at least two years following the date of such measurements, maintenance, reports, and records.
(f) If notification substantially similar to that in 40 CFR 60.7(a) is required by any other State or local agency, sending the Administrator a copy of that notification will satisfy the requirements of 40 CFR 60.7(a).
(g) Individual subparts of this part may include specific provisions which clarify or make inapplicable the provisions set forth in this section.
[Rule 62-204.800, F.A.C.; and, 40 CFR 60.7(a), (b), (c), (d), (e), (f) and (g)]

40 CFR 60.8 Performance tests.

(a) Within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of such facility and at such other times as may be required by the Administrator under section 114 of the Act, the owner or operator of such facility shall conduct performance test(s) and furnish the Administrator a written report of the results of such performance test(s).
(b) Performance tests shall be conducted and data reduced in accordance with the test methods and procedures contained in each applicable subpart unless the Administrator (1) specifies or approves, in specific cases, the use of a reference method with minor changes in methodology, (4) waives the requirement for performance tests because the owner or operator of a source has demonstrated by other means to the Administrator's satisfaction that the affected facility is in compliance with the standard, or (5) approves shorter sampling times and smaller sample volumes when necessitated by process variables or other factors. Nothing in 40 CFR 60.8 shall be construed to abrogate the Administrator's authority to require testing under section 114 of the Act.
(c) Performance tests shall be conducted under such conditions as the Administrator shall specify to the plant operator based on representative performance of the affected facility. The owner or operator shall make available to the Administrator such records as may be necessary to determine the conditions of the performance tests. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a performance test nor shall emissions in excess of the level of the applicable emission limit during periods of startup, shutdown, and malfunction be considered a violation of the applicable emission limit unless otherwise specified in the applicable standard.
(e) The owner or operator of an affected facility shall provide, or cause to be provided, performance testing facilities as follows:

(1) Sampling ports adequate for test methods applicable to such facility. This includes (i) constructing the air pollution control system such that volumetric flow rates and pollutant emission rates can be accurately determined by applicable test methods and procedures and (ii) providing a stack or duct free of cyclonic flow during performance tests, as demonstrated by applicable test methods and procedures.
(2) Safe sampling platform(s).
(3) Safe access to sampling platform(s).
(4) Utilities for sampling and testing equipment.

(f) Unless otherwise specified in the applicable subpart, each performance test shall consist of three separate runs using the applicable test method. Each run shall be conducted for the time and under the conditions specified in the applicable standard. For the purpose of determining compliance with an applicable standard, the arithmetic means of results of the three runs shall apply. In the event that a sample is accidentally lost or conditions occur in which one of the three runs must be discontinued because of forced shutdown, failure of an irreplaceable portion of the sample train, extreme meteorological conditions, or other circumstances, beyond the owner or operator's control, compliance may, upon the Administrator's approval, be determined using the arithmetic mean of the results of the two other runs.
[Rule 62-204.800, F.A.C.; and, 40 CFR 60.8(a), (b)(1), (4) & (5), (c), (e) and (f)]

40 CFR 60.10 State authority.

The provisions of 40 CFR 60 shall not be construed in any manner to preclude any State or political subdivision thereof from:
(a) Adopting and enforcing any emission standard or limitation applicable to an affected facility, provided that such emission standard or limitation is not less stringent than the standard applicable to such facility.
(b) Requiring the owner or operator of an affected facility to obtain permits, licenses, or approvals prior to initiating construction, modification, or operation of such facility.
[Rule 62-204.800, F.A.C.; and, 40 CFR 60.10(a) and (b)].

40 CFR 60.11 Compliance with standards and maintenance requirements.

(a) Compliance with standards in this part, other than opacity standards, shall be determined by performance tests established by 40 CFR 60.8, unless otherwise specified in the applicable standard.
(b) Compliance with opacity standards in this part shall be determined by conducting observations in accordance with Reference Method 9 in appendix A of this part, any alternative method that is approved by the Administrator, or as provided in 40 CFR 60.11(e)(5). For purposes of determining initial compliance, the minimum total time of observations shall be 3 hours (30 6-minute averages) for the performance test or other set of observations (meaning those fugitive-type emission sources subject only to an opacity standard).
(c) The opacity standards set forth in this part shall apply at all times except during periods of startup, shutdown, malfunction, and as otherwise provided in the applicable standard.
(d) At all times, including periods of startup, shutdown, and malfunction, owners and operators shall, to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.
(e)(1) For the purpose of demonstrating initial compliance, opacity observations shall be conducted concurrently with the initial performance test required in 40 CFR 60.8 unless one of the following conditions apply. If no performance test under 40 CFR 60.8 is required, then opacity observations shall be conducted within 60 days after achieving the maximum production rate at which the affected facility will be operated but no later than 180 days after initial startup of the facility. If visibility or other conditions prevent the opacity observations from being conducted concurrently with the initial performance test required under 40 CFR 60.8, the source owner or operator shall reschedule the opacity observations as soon after the initial performance test as possible, but not later than 30 days thereafter, and shall advise the Administrator of the rescheduled date. In these cases, the 30-day prior notification to the Administrator required in 40 CFR 60.7(a)(6) shall be waived. The rescheduled opacity observations shall be conducted (to the extent possible) under the same operating conditions that existed during the initial performance test conducted under 40 CFR 60.8. The visible emissions observer shall determine whether visibility or other conditions prevent the opacity observations from being made concurrently with the initial performance test in accordance with procedures contained in Reference Method 9 of appendix B of this part. Opacity readings of portions of plumes which contain condensed, uncombined water vapor shall not be used for purposes of determining compliance with opacity standards. The owner or operator of an affected facility shall make available, upon request by the Administrator, such records as may be necessary to determine the conditions under which the visual observations were made and shall provide evidence indicating proof of current visible observer emission certification. Except as provided in 40 CFR 60.11(e)(5), the results of continuous monitoring by transmissometer which indicate that the opacity at the time visual observations were made was not in excess of the standard are probative but not conclusive evidence of the actual opacity of an emission, provided that the source shall meet the burden of proving that the instrument used meets (at the time of the alleged violation) Performance Specification 1 in appendix B of 40 CFR 60, has been properly maintained and (at the time of the alleged violation) that the resulting data have not been altered in any way.

(2) Except as provided in 40 CFR 60.11(e)(3), the owner or operator of an affected facility to which an opacity standard in this part applies shall conduct opacity observations in accordance with 40 CFR 60.11(b), shall record the opacity of emissions, and shall report to the Administrator the opacity results along with the results of the initial performance test required under 40 CFR 60.8. The inability of an owner or operator to secure a visible emissions observer shall not be considered a reason for not conducting the opacity observations concurrent with the initial performance test.
(3) The owner or operator of an affected facility to which an opacity standard in this part applies may request the Administrator to determine and to record the opacity of emissions from the affected facility during the initial performance test and at such times as may be required. The owner or operator of the affected facility shall report the opacity results. Any request to the Administrator to determine and to record the opacity of emissions from an affected facility shall be included in the notification required in 40 CFR 60.7(a)(6). If, for some reason, the Administrator cannot determine and record the opacity of emissions from the affected facility during the performance test, then the provisions of 40 CFR 60.7(e)(1) shall apply.
(4) The owner or operator of an affected facility using a continuous opacity monitor (transmissometer) shall record the monitoring data produced during the initial performance test required by 40 CFR 60.8 and shall furnish the Administrator a written report of the monitoring results along with Method 9 and 40 CFR 60.8 performance test results.
(5) The owner or operator of an affected facility subject to an opacity standard may submit, for compliance purposes, continuous opacity monitoring system (COMS) data results produced during any performance test required under 40 CFR 60.8 in lieu of Method 9 observation data. If an owner or operator elects to submit COMS data for compliance with the opacity standard, he shall notify the Administrator of that decision, in writing, at least 30 days before any performance test required under 40 CFR 60.8 is conducted. Once the owner or operator of an affected facility has notified the Administrator to that effect, the COMS data results will be used to determine opacity compliance during subsequent tests required under 40 CFR 60.8 until the owner or operator notifies the Administrator, in writing, to the contrary. For the purpose of determining compliance with the opacity standard during a performance test required under 40 CFR 60.8 using COMS data, the minimum total time of COMS data collection shall be averages of all 6-minute continuous periods within the duration of the mass emission performance test. Results of the COMS opacity determinations shall be submitted along with the results of the performance test required under 60.8. The owner or operator of an affected facility using a COMS for compliance purposes is responsible for demonstrating that the COMS meets the requirements specified in 40 CFR 60.13(c), that the COMS has been properly maintained and operated, and that the resulting data have not been altered in any way. If COMS data results are submitted for compliance with the opacity standard for a period of time during which Method 9 data indicates noncompliance, the Method 9 data will be used to determine opacity compliance.
(6) Upon receipt from an owner or operator of the written reports of the results of the performance tests required by 40 CFR 60.8, the opacity observation results and observer certification required by 40 CFR 60.11(e)(1), and the COMS results, if applicable, the Administrator will make a finding concerning compliance with opacity and other applicable standards. If COMS data results are used to comply with an opacity standard, only those results are required to be submitted along with the performance test results required by 40 CFR 60.8. If the Administrator finds that an affected facility is in compliance with all applicable standards for which performance tests are conducted in accordance with 40 CFR 60.8 of this part but during the time such performance tests are being conducted fails to meet any applicable opacity standard, the shall notify the owner or operator and advise him that he may petition the Administrator within 10 days of receipt of notification to make appropriate adjustment to the opacity standard for the affected facility.
(7) The Administrator will grant such a petition upon a demonstration by the owner or operator that the affected facility and associated air pollution control equipment was operated and maintained in a manner to minimize the opacity of emissions during the performance tests; that the performance tests were performed under the conditions established by the Administrator; and that the affected facility and associated air pollution control equipment were incapable of being adjusted or operated to meet the applicable opacity standard.

(8) The Administrator will establish an opacity standard for the affected facility meeting the above requirements at a level at which the source will be able, as indicated by the performance and opacity tests, to meet the opacity standard at all times during which the source is meeting the mass or concentration emission standard. The Administrator will promulgate the new opacity standard in the Federal Register.

(f) Special provisions set forth under an applicable subpart of 40 CFR 60 shall supersede any conflicting provisions of 40 CFR 60.11.

(g) For the purpose of submitting compliance certifications or establishing whether or not a person has violated or is in violation of any standard in this part, nothing in this part shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.

[Rule 62-204.800, F.A.C.; and, 40 CFR 60.11(a), (b), (c), (d), (e), (f) and (g)]

40 CFR 60.12 Circumvention.

No owner or operator subject to the provisions of this part shall build, erect, install, or use any article, machine, equipment or process, the use of which conceals an emission which would otherwise constitute a violation of an applicable standard. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with an opacity standard or with a standard which is based on the concentration of a pollutant in the gases discharged to the atmosphere.

[Rule 62-204.800, F.A.C.; and, 40 CFR 60.12]

40 CFR 60.13 Monitoring requirements.

(a) For the purposes of this section, all continuous monitoring systems required under applicable subparts shall be subject to the provisions of this section upon promulgation of performance specifications for continuous monitoring systems under appendix B of 40 CFR 60 and, if the continuous monitoring system is used to demonstrate compliance with emission limits on a continuous basis, appendix F to 40 CFR 60, unless otherwise specified in an applicable subpart or by the Administrator. Appendix F is applicable December 4, 1987.

(b) All continuous monitoring systems and monitoring devices shall be installed and operational prior to conducting performance tests under 40 CFR 60.8. Verification of operational status shall, as a minimum, include completion of the manufacturer's written requirements or recommendations for installation, operation, and calibration of the device.

(c) If the owner or operator of an affected facility elects to submit continuos opacity monitoring system (COMS) data for compliance with the opacity standard as provided under 40 CFR 60.11(e)(5), he/she shall conduct a performance evaluation of the COMS as specified in Performance Specification 1, appendix B, of 40 CFR 60 before the performance test required under 40 CFR 60.8 is conducted. Otherwise, the owner or operator of an affected facility shall conduct a performance evaluation of the COMS or continuous emission monitoring system (CEMS) during any performance test required under 40 CFR 60.8 or within 30 days thereafter in accordance with the applicable performance specification in appendix B of 40 CFR 60. The owner or operator of an affected facility shall conduct COMS or CEMS performance evaluations at such other times as may be required by the Administrator under section 114 of the Act.

(1) The owner or operator of an affected facility using a COMS to determine opacity compliance during any performance test required under 40 CFR 60.8 and as described in 40 CFR 60.11(e)(5), shall furnish the Administrator two or, upon request, more copies of a written report of the results of the COMS performance evaluation described in 40 CFR 60.13(c) at least 10 days before the performance test required under 40 CFR 60.8 is conducted.

(2) Except as provided in 40 CFR 60.13(c)(1), the owner or operator of an affected facility shall furnish the Administrator within 60 days of completion two or, upon request, more copies of a written report of the results of the performance evaluation.

(d)(1) Owners and operators of all continuous emission monitoring systems installed in accordance with the provisions of this part shall check the zero (or low-level value between 0 and 20 percent of span value) and span (50 to 100 percent of span value) calibration drifts at least once daily in accordance with a written procedure. The zero and span shall, as a minimum, be adjusted whenever the 24-hour zero drift or 24-hour span drift exceeds two times the limits of the applicable performance specifications in appendix B. The system must allow the amount of excess zero and span drift measured at the 24-hour interval checks to be recorded and quantified, whenever specified. For continuous monitoring systems measuring opacity of emissions, the optical surfaces exposed to the effluent gases shall be cleaned prior to performing the zero and span drift adjustments except that for systems using automatic zero adjustments. The optical surfaces shall be cleaned when the cumulative automatic zero compensation exceeds 4 percent opacity.

(2) Unless otherwise approved by the Administrator, the following procedures shall be followed for continuous monitoring systems measuring opacity of emissions. Minimum procedures shall include a method for producing a simulated zero opacity condition and an upscale (span) opacity condition using a certified neutral density filter or other related technique to produce a known obscuration of the light beam. Such procedures shall provide a system check of the analyzer internal optical surfaces and all electronic circuitry including the lamp and photo detector assembly.

(e) Except for system breakdowns, repairs, calibration checks, and zero and span adjustments required under 40 CFR 60.13(d), all continuous monitoring systems shall be in continuous operation and shall meet minimum frequency of operation requirements as follows:

(1) All continuous monitoring systems referenced by 40 CFR 60.13(c) for measuring opacity of emissions shall complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period.

(2) All continuous monitoring systems referenced by 40 CFR 60.13(c) for measuring emissions, except opacity, shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

(f) All continuous monitoring systems or monitoring devices shall be installed such that representative measurements of emissions or process parameters from the affected facility are obtained. Additional procedures for location of continuous monitoring systems contained in the applicable Performance Specifications of appendix B of 40 CFR 60 shall be used.

(g) When the effluents from a single affected facility or two or more affected facilities subject to the same emission standards are combined before being released to the atmosphere, the owner or operator may install applicable continuous monitoring systems on each effluent or on the combined effluent. When the affected facilities are not subject to the same emission standards, separate continuous monitoring systems shall be installed on each effluent. When the effluent from one affected facility is released to the atmosphere through more than one point, the owner or operator shall install an applicable continuous monitoring system on each separate effluent unless the installation of fewer systems is approved by the Administrator. When more than one continuous monitoring system is used to measure the emissions from one affected facility (e.g., multiple breechings, multiple outlets), the owner or operator shall report the results as required from each continuous monitoring system.

(h) Owners or operators of all continuous monitoring systems for measurement of opacity shall reduce all data to 6-minute averages and for continuous monitoring systems other than opacity to 1-hour averages for time periods as defined in 40 CFR 60.2. Six-minute opacity averages shall be calculated from 36 or more data points equally spaced over each 6-minute period. For continuous monitoring systems other than opacity, 1-hour averages shall be computed from four or more data points equally spaced over each 1-hour period. Data recorder during periods of continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments shall not be included in the data averages computed under this paragraph. An arithmetic or integrated average of all data may be used. The data may be recorded in reduced or non reduced form (e.g., ppm pollutant and percent O2 or ng/J of pollutant). All excess emissions shall be converted into units of the standard using the applicable conversion procedures specified in subparts. After conversion into units of the standard, the data may be rounded to the same number of significant digits as used in the applicable subparts to specify the emission limit (e.g., rounded to the nearest 1 percent opacity).

(i) After receipt and consideration of written application, the Administrator may approve alternatives to any monitoring procedures or requirements of this part including, but not limited to the following:

(1) Alternative monitoring requirements when installation of a continuous monitoring system or monitoring device specified by this part would not provide accurate measurements due to liquid water or other interferences caused by substances with the effluent gases.

(2) Alternative monitoring requirements when the affected facility is infrequently operated.

(3) Alternative monitoring requirements to accommodate continuous monitoring systems that require additional measurements to correct for stack moisture conditions.

(4) Alternative locations for installing continuous monitoring systems or monitoring devices when the owner or operator can demonstrate that installation at alternate locations will enable accurate and representative measurements.

(5) Alternative methods of converting pollutant concentration measurements to units of the standards.

(6) Alternative procedures for performing daily checks of zero and span drift that do not involve use of span gases or test cells.

(7) Alternatives to the A.S.T.M. test methods or sampling procedures specified by any subpart.

(8) Alternative continuous monitoring systems that do not meet the design or performance requirements in Performance Specification 1, appendix B, but adequately demonstrate a definite and consistent relationship between its measurements and the measurements of opacity by a system complying with the requirements in Performance Specification 1. The Administrator may require that such demonstration be performed for each affected facility.

(9) Alternative monitoring requirements when the effluent from a single affected facility or the combined effluent from two or more affected facilities are released to the atmosphere through more than one point.

(j) An alternative to the relative accuracy test specified in Performance Specification 2 of appendix B may be requested as follows:

(1) An alternative to the reference method tests for determining relative accuracy is available for sources with emission rates demonstrated to be less than 50 percent of the applicable standard. A source owner or operator may petition the Administrator to waive the relative accuracy test in section 7 of Performance Specification 2 and substitute the procedures in section 10 if the results of a performance test conducted according to the requirements in 40 CFR 60.8 of this subpart or other tests performed following the criteria in 40 CFR 60.8 demonstrate that the emission rate of the pollutant of interest in the units of the applicable standard is less than 50 percent of the applicable standard. For sources subject to standards expressed as control efficiency levels, a source owner or operator may petition the Administrator to waive the relative accuracy test and substitute the procedures in section 10 of Performance Specification 2 if the control device exhaust emission rate is less than 50 percent of the level needed to meet the control efficiency requirement. The alternative procedures do not apply if the continuous emission monitoring system is used to determine compliance continuously with the applicable standard. The petition to waive the relative accuracy test shall include a detailed description of the procedures to be applied. Included shall be location and procedure for conducting the alternative, the concentration or response levels of the alternative RA materials, and the other equipment checks included in the alternative procedure. The Administrator will review the petition for completeness and applicability. The determination to grant a waiver will depend on the intended use of the CEMS data (e.g., data collection purposes other than NSPS) and may require specifications more stringent than in Performance Specification 2 (e.g., the applicable emission limit is more stringent than NSPS).

(2) The waiver of a CEMS relative accuracy test will be reviewed and may be rescinded at such time following successful completion of the alternative RA procedure that the CEMS data indicate the source emissions approaching the level of the applicable standard. The criterion for reviewing the waiver is the collection of CEMS data showing that emissions have exceeded 70 percent of the applicable standard for seven, consecutive, averaging periods as specified by the applicable regulation(s). For sources subject to standards expressed as control efficiency levels, the criterion for reviewing the waiver is the collection of CEMS data showing that exhaust emissions have exceeded 70 percent of the level needed to meet the control efficiency requirement for seven, consecutive, averaging periods as specified by the applicable regulation(s) [e.g., 40 CFR 60.45(g)(2) and 40 CFR 60.45(g)(3), 40 CFR 60.73(e), and 40 CFR 60.84(e)]. It is the

responsibility of the source operator to maintain records and determine the level of emissions relative to the criterion on the waiver of relative accuracy testing. If this criterion is exceeded, the owner or operator must notify the Administrator within 10 days of such occurrence and include a description of the nature and cause of the increasing emissions. The Administrator will review the notification and may rescind the waiver and require the owner or operator to conduct a relative accuracy test of the CEMS as specified in section 7 of Performance Specification 2.

[Rule 62-204.800, F.A.C.; and, 40 CFR 60.13(a) thru (j)].

40 CFR 60.14 Modification.

(a) Except as provided under 40 CFR 60.14(e) and 40 CFR 60.14(f), any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies shall be considered a modification within the meaning of section 111 of the Act. Upon modification, an existing facility shall become an affected facility for each pollutant to which a standard applies and for which there is an increase in the emission rate to the atmosphere.

(b) Emission rate shall be expressed as kg/hr (lbs/hour) of any pollutant discharged into the atmosphere for which a standard is applicable. The Administrator shall use the following to determine emission rate:

(1) Emission factors as specified in the latest issue of "Compilation of Air Pollutant Emission Factors", EPA Publication No. AP-42, or other emission factors determined by the Administrator to be superior to AP-42 emission factors, in cases where utilization of emission factors demonstrate that the emission level resulting from the physical or operational change will either clearly increase or clearly not increase.

(2) Material balances, continuous monitor data, or manual emission tests in cases where utilization of emission factors as referenced in 40 CFR 60.14(b)(1) does not demonstrate to the Administrator's satisfaction whether the emission level resulting from the physical or operational change will either clearly increase or clearly not increase, or where an owner or operator demonstrates to the Administrator's satisfaction that there are reasonable grounds to dispute the result obtained by the Administrator utilizing emission factors as referenced in 40 CFR 60.14(b)(1) . When the emission rate is based on results from manual emission tests or continuous monitoring systems, the procedures specified in 40 CFR 60 appendix C of 40 CFR 60 shall be used to determine whether an increase in emission rate has occurred. Tests shall be conducted under such conditions as the Administrator shall specify to the owner or operator based on representative performance of the facility. At least three valid test runs must be conducted before and at least three after the physical or operational change. All operating parameters which may affect emissions must be held constant to the maximum feasible degree for all test runs.

(c) The addition of an affected facility to a stationary source as an expansion to that source or as a replacement for an existing facility shall not by itself bring within the applicability of this part any other facility within that source.

(d) [Reserved]

(e) The following shall not, by themselves, be considered modifications under this part:

(1) Maintenance, repair, and replacement which the Administrator determines to be routine for a source category, subject to the provisions of 40 CFR 60.14(c) and 40 CFR 60.15.

(2) An increase in production rate of an existing facility, if that increase can be accomplished without a capital expenditure on that facility.

(3) An increase in the hours of operation.

(4) Use of an alternative fuel or raw material if, prior to the date any standard under this part becomes applicable to that source type, as provided by 40 CFR 60.1, the existing facility was designed to accommodate that alternative use. A facility shall be considered to be designed to accommodate an alternative fuel or raw material if that use could be accomplished under the facility's construction specifications as amended prior to the change. Conversion to coal required for energy considerations, as specified in section 111(a)(8) of the Act, shall not be considered a modification.

(5) The addition or use of any system or device whose primary function is the reduction of air pollutants, except when an emission control system is removed or is replaced by a system which the Administrator determines to be less environmentally beneficial.

(6) The relocation or change in ownership of an existing facility.

(f) Special provisions set forth under an applicable subpart of this part shall supersede any conflicting provisions of this section.

(g) Within 180 days of the completion of any physical or operational change subject to the control measures specified in 40 CFR 60.14(a), compliance with all applicable standards must be achieved.

[Rule 62-204.800, F.A.C.; and, 40 CFR 60.14(a) thru (g)].

40 CFR 60.15 Reconstruction.

(a) An existing facility, upon reconstruction, becomes an affected facility, irrespective of any change in emission rate.

(b) "Reconstruction" means the replacement of components of an existing facility 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 entirely new facility, and

(2) It is technologically and economically feasible to meet the applicable standards set forth in this part.

(c) "Fixed capital cost"' means the capital needed to provide all the depreciable components.

(d) If an owner or operator of an existing facility proposes to replace components, and the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, he shall notify the Administrator of the proposed replacements. The notice must be postmarked 60 days (or as soon as practicable) before construction of the replacements is commenced and must include the following information:

(1) Name and address of the owner or operator.

(2) The location of the existing facility.

(3) A brief description of the existing facility and the components which are to be replaced.

(4) A description of the existing air pollution control equipment and the proposed air pollution control equipment.

(5) An estimate of the fixed capital cost of the replacements and of constructing a comparable entirely new facility.

(6) The estimated life of the existing facility after the replacements.

(7) A discussion of any economic or technical limitations the facility may have in complying with the applicable standards of performance after the proposed replacements.

(e) The Administrator will determine, within 30 days of the receipt of the notice required by 40 CFR 60.15(d) and any additional information he may reasonably require, whether the proposed replacement constitutes reconstruction.

(f) The Administrator's determination under 40 CFR 60.15(e) shall be based on:

(1) The fixed capital cost of the replacements in comparison to the fixed capital cost that would be required to construct a comparable entirely new facility;

(2) The estimated life of the facility after the replacements compared to the life of a comparable entirely new facility;

(3) The extent to which the components being replaced cause or contribute to the emissions from the facility; and

(4) Any economic or technical limitations on compliance with applicable standards of performance which are inherent in the proposed replacements.

(g) Individual subparts of this part may include specific provisions which refine and delimit the concept of reconstruction set forth in this section.

[Rule 62-204.800, F.A.C.; and, 40 CFR 60.15(a) thru (g)].

Tables to Subpart DDDDD of Part 63

TABLE 1 TO SUBPART DDDDD OF PART 63.—EMISSION LIMITS AND WORK PRACTICE STANDARDS

As stated in § 63.7500, you must comply with the following applicable emission limits and work practice standards:

If your boiler or process heater is in this subcategory	For the following pollutants	You must meet the following emission limits and work practice standards
1. New or reconstructed large solid fuel	a. Particulate Matter (or Total Selected Metals).	0.025 lb per MMBtu of heat input; or (0.0003 lb per MMBtu of heat input).
	b. Hydrogen Chloride	0.02 lb per MMBtu of heat input.
	c. Mercury	0.000003 lb per MMBtu of heat input.
	d. Carbon Monoxide	400 ppm by volume on a dry basis corrected to 7 percent oxygen (30-day rolling average for units 100 MMBtu/hr or greater, 3-run average for units less than 100 MMBtu/hr).
2. New or reconstructed limited use solid fuel	a. Particulate Matter (or Total Selected Metals).	0.025 lb per MMBtu of heat input; or (0.0003 lb per MMBtu of heat input).
	b. Hydrogen Chloride	0.02 lb per MMBtu of heat input.
	c. Mercury	0.000003 lb per MMBtu of heat input.
	d. Carbon Monoxide	400 ppm by volume on a dry basis corrected to 7 percent oxygen (3-run average).
3. New or reconstructed small solid fuel	a. Particulate Matter (or Total Selected Metals).	0.025 lb per MMBtu of heat input; or (0.0003 lb per MMBtu of heat input).
	b. Hydrogen Chloride	0.02 lb per MMBtu of heat input.
	c. Mercury	0.000003 lb per MMBtu of heat input.
4. New reconstructed large liquid fuel	a. Particulate Matter	0.03 lb per MMBtu of heat input.
	b. Hydrogen Chloride	0.0005 lb per MMBtu of heat input.
	c. Carbon Monoxide	400 ppm by volume on a dry basis corrected to 3 percent oxygen (30-day rolling average for units 100 MMBtu/hr or greater, 3-run average for units less than 100 MMBtu/hr).
5. New or reconstructed limited use liquid fuel	a. Particulate Matter	0.03 lb per MMBtu of heat input.
	b. Hydrogen Chloride	0.0009 lb per MMBtu of heat input.
	c. Carbon Monoxide	400 ppm by volume on a dry basis liquid corrected to 3 percent oxygen (3-run average).
6. New or reconstructed small liquid fuel	a. Particulate Matter	0.03 lb per MMBtu of heat input.
	b. Hydrogen Chloride	0.0009 lb per MMBtu of heat input.
7. New reconstructed large gaseous fuel	Carbon Monoxide	400 ppm by volume on a dry basis corrected to 3 percent oxygen (30-day rolling average for units 100 MMBtu/hr or greater, 3-run average for units less than 100 MMBtu/hr).
8. New or reconstructed limited use gaseous fuel.	Carbon Monoxide	400 ppm by volume on a dry basis corrected to 3 percent oxygen (3-run average).
9. Existing large solid fuel	a. Particulate Matter (or Total Selected Metals).	0.07 lb per MMBtu of heat input; or (0.001 lb per MMBtu of heat input).
	b. Hydrogen Chloride	0.09 lb per MMBtu of heat input.
	c. Mercury	0.000009 lb per MMBtu of heat input.
10. Existing limited use solid fuel	Particulate Matter (or Total Selected Metals)	0.21 lb per MMBtu of heat input; or (0.004 lb per MMBtu of heat input).

TABLE 2 TO SUBPART DDDDD OF PART 63.—OPERATING LIMITS FOR BOILERS AND PROCESS HEATERS WITHPARTICULATE MATTER EMISSION LIMITS

As stated in § 63.7500, you must comply with the applicable operating limits:

If you demonstrate compliance with applicable particulate matter emission limits using	You must meet these operating limits
1. Wet scrubber control	a. Maintain the minimum pressure drop and liquid flow-rate at or above the operating levels established during the performance test according to § 63.7530(c) and Table 7 to this subpart that demonstrated compliance with the applicable emission limit for particulate matter.
2. Fabric filter control	a. Install and operate a bag leak detection system according to § 63.7525 and operate the fabric filter such that the bag leak detection system alarm does not sound more than 5 percent of the operating time during each 6-month period; or
	b. This option is for boilers and process heaters that operate dry control systems. Existing boilers and process heaters must maintain opacity to less than or equal to 20 percent (6-minute average) except for one 6-minute period per hour of not more than 27 percent. New boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity (1-hour block average).
3. Electrostatic precipitator control	a. This option is for boilers and process heaters that operate dry control systems. Existing boilers and process heaters must maintain opacity to less than or equal to 20 percent (6-minute average) except for one 6-minute period per hour of not more than 27 percent. New boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity (1-hour block average); or
	b. This option is only for boilers and process heaters that operate additional wet control systems. Maintain the minimum voltage and secondary current or total power input of the electrostatic precipitator at or above the operating limits established during the performance test according to § 63.7530(c) and Table 7 to this subpart that demonstrated compliance with the applicable emission limit for particulate matter.
4. Any other control type	This option is for boilers and process heaters that operate dry control systems. Existing boilers and process heaters must maintain opacity to less than or equal to 20 percent (6-minute average) except for one 6-minute period per hour of not more than 27 percent. New boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity (1-hour block average).

TABLE 3 TO SUBPART DDDDD OF PART 63.—OPERATING LIMITS FOR BOILERS AND PROCESS HEATERS WITH MERCURY EMISSION LIMITS AND BOILERS AND PROCESS HEATERS THAT CHOOSE TO COMPLY WITH THE ALTERNATIVE TOTAL SELECTED METALS EMISSION LIMITS

As stated in § 63.7500, you must comply with the applicable operating limits:

If you demonstrate compliance with applicable mercury and/or total selected metals emission limits using	You must meet these operating limits
1. Wet scrubber control	Maintain the minimum pressure drop and liquid flow-rate at or above the operating levels established during the performance test according to § 63.7530(c) and Table 7 to this subpart that demonstrated compliance with the applicable emission limits for mercury and/or total selected metals.
2. Fabric filter control	a. Install and operate a bag leak detection system according to § 63.7525 and operate the fabric filter such that the bag leak detection system alarm does not sound more than 5 percent of the operating time during a 6-month period; or
	b. This option is for boilers and process heaters that operate dry control systems. Existing sources must maintain opacity to less than or equal to 20 percent (6-minute average) except for one 6-minute period per hour of not more than 27 percent. New sources must maintain opacity to less than or equal to 10 percent opacity (1-hour block average).
3. Electrostatic precipitator control	a. This option is for boilers and process heaters that operate dry control systems. Existing sources must maintain opacity to less than or equal to 20 percent (6-minute average) except for one 6-minute period per hour of not more than 27 percent. New sources must maintain opacity to less than or equal to 10 percent opacity (1-hour block average); or b. This option is only for boilers and process heaters that operate additional wet control systems. Maintain the minimum voltage and secondary current or total power input of the electrostatic precipitator at or above the operating limits established during the performance test according to § 63.7530(c) and Table 7 to this subpart that demonstrated compliance with the applicable emission limits for mercury and/or total selected metals.
4. Dry scrubber or carbon injection control	Maintain the minimum sorbent or carbon injection rate at or above the operating levels established during the performance test according to § 63.7530(c) and Table 7 to this subpart that demonstrated compliance with the applicable emission limit for mercury.
5. Any other control type	This option is only for boilers and process heaters that operate dry control systems. Existing sources must maintain opacity to less than or equal to 20 percent (6-minute average) except for one 6-minute period per hour of not more than 27 percent. New sources must maintain opacity to less than or equal to 10 percent opacity (1-hour block average).
6. Fuel analysis	Maintain the fuel type or fuel mixture such that the mercury and/or total selected metals emission rates calculated according to § 63.7530(d)(4) and/or (5) is less than the applicable emission limits for mercury and/or total selected metals.

TABLE 4 TO SUBPART DDDDD OF PART 63.—OPERATING LIMITS FOR BOILERS AND PROCESS HEATERS WITH HYDROGEN CHLORIDE EMISSION LIMITS

As stated in § 63.7500, you must comply with the following applicable operating limits:

If you demonstrate compliance with applicable hydrogen chloride emission limits using	You must meet these operating limits
1. Wet scrubber control	Maintain the minimum scrubber effluent pH, pressure drop, and liquid flow-rate at or above the operating levels established during the performance test according to § 63.7530(c) and Table 7 to this subpart that demonstrated compliance with the applicable emission limit for hydrogen chloride.
2. Dry scrubber control	Maintain the minimum sorbent injection rate at or above the operating levels established during the performance test according to § 63.7530(c) and Table 7 to this subpart that demonstrated compliance with the applicable emission limit for hydrogen chloride.
3. Fuel analysis	Maintain the fuel type or fuel mixture such that the hydrogen chloride emission rate calculated according to § 63.7530(d)(3) is less than the applicable emission limit for hydrogen chloride.

TABLE 5 TO SUBPART DDDDD OF PART 63.—PERFORMANCE TESTING REQUIREMENTS

As stated in § 63.7520, you must comply with the following requirements for performance test for existing, new or reconstructed affected sources:

To conduct a performance test for the following pollutant	You must	Using
1. Particulate Matter	a. Select sampling ports location and the number of traverse points.	Method 1 in appendix A to part 60 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2F, or 2G in appendix A to part 60 of this chapter.
	c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B in appendix A to part 60 of this chapter, or ASME PTC 19, Part 10 (1981) (IBR, see § 63.14(i)).
	d. Measure the moisture content of the stack gas.	Method 4 in appendix A to part 60 of this chapter.
	e. Measure the particulate matter emission concentration.	Method 5 or 17 (positive pressure fabric filters must use Method 5D) in appendix A to part 60 of this chapter.
	f. Convert emissions concentration to lb per MMBtu emission rates.	Method 19 F-factor methodology in appendix A to part 60 of this chapter.
2. Total selected metals	a. Select sampling ports location and the number of traverse points.	Method 1 in appendix A to part 60 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2F, or 2G in appendix A to part 60 of this chapter.
	c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B in appendix A to part 60 of this chapter, or ASME PTC 19. Part 10 (1981) (IBR. see § 63.14(i)).
	d. Measure the moisture content of the stack gas.	Method 4 in appendix A to part 60 of this chapter.
	e. Measure the particulate matter emission concentration.	Method 29 in appendix A to part 60 of this chapter.
	f. Convert emissions concentration to lb per MMBtu emission rates.	Method 19 F-factor methodology in appendix A to part 60 of this chapter.
3. Hydrogen chloride	a. Select sampling ports location and the number of traverse points.	Method 1 in appendix A to part 60 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2F, or 2G in appendix A to part 60 of this chapter.
	c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B in appendix A to part 60 of this chapter, or ASME PTC 19, Part 10 (1981) (IBR, see § 63.14(i)).
	d. Measure the moisture content of the stack gas.	Method 4 in appendix A to part 60 of this chapter.
	e. Measure the particulate matter emission concentration.	Method 26 or 26A in appendix A to part 60 of this chapter.
	f. Convert emissions concentration to lb per MMBtu emission rates.	Method 19 F-factor methodology in appendix A to part 60 of this chapter.
4. Mercury	a. Select sampling ports location and the number of traverse points	Method 1 in appendix A to part 60 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2F, or 2G in appendix A to part 60 of this chapter.
	c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B in appendix A to part 60 of this chapter, or ASME PTC 19, Part 10 (1981) (IBR, see § 62.14(i)).
	d. Measure the moisture content of the stack gas.	Method 4 in appendix A to part 60 of this chapter.
	e. Measure the particulate matter emission concentration.	Method 29 in appendix A to part 60 of this chapter or Method 101A in appendix B to part 61 of this chapter or ASTM Method D6784–02 (IBR, see § 63.14(b)).
	f. Convert emissions concentration to lb per MMBtu emission rates.	Method 19 F-factor methodology in appendix A to part 60 of this chapter.
5. Carbon Monoxide	a. Select the sampling ports location and the number of traverse points.	Method 1 in appendix A to part 60 of thischapter.
	b. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B in appendix A to part 60 of this chapter, or ASTM D6522–00 (IBR, see § 63.14(b)), or ASME PTC 19, Part 10 (1981) (IBR, see § 63.14(i)).
	c. Measure the moisture content of the stack gas.	Method 4 in appendix A to part 60 of this chapter.
	d. Measure the carbon monoxide emission concentration.	Method 10, 10A, or 10B in appendix A to part 60 of this chapter, or ASTM D6522–00 (IBR, see § 63.14(b)) when the fuel is natural gas.

TABLE 6 TO SUBPART DDDDD OF PART 63—FUEL ANALYSIS REQUIREMENTS

As stated in § 63.7521, you must comply with the following requirements for fuel analysis testing for existing, new or reconstructed affected sources:

To conduct a fuel analysis for the following pollutant	You must	Using
1. Mercury	a. Collect fuel samples	Procedure in § 63.7521(c) or ASTM D2234–00 □1 (for coal)(IBR, see § 63.14(b)) or ASTM D6323–98 (2003)(for biomass)(IBR, see § 63.14(b)) or equivalent.
	b. Composite fuel samples	Procedure in § 63.7521(d) or equivalent.
	c. Prepare composited fuel samples	SW–846–3050B (for solid samples) or SW– 846–3020A (for liquid samples) or ASTM D2013–01 (for coal) (IBR, see § 63.14(b)) or ASTM D5198–92 (2003) (for biomass)(IBR, see § 63.14(b)) or equivalent.
	d. Determine heat content of the fuel type	ASTM D5865–03a (for coal)(IBR, see § 63.14(b)) or ASTM E711–87 (1996) (for biomass)(IBR, see § 63.14(b)) or equivalent.
	e. Determine moisture content of the fuel type	ASTM D3173–02 (IBR, see § 63.14(b)) or ASTM E871–82 (1998)(IBR, see § 63.14(b)) or equivalent.
	f. Measure mercury concentration in fuel sample.	ASTM D3684–01 (for coal)(IBR, see § 63.14(b)) or SW–846–7471A (for solid samples) or SW–846 7470A (for liquid samples).
	g. Convert concentrations into units of pounds of pollutant per MMBtu of heat content.	
2. Total selected metals	a. Collect fuel samples	Procedure in § 63.7521(c) or ASTM D2234–00 □1 (for coal)(IBR, see § 63.14(b)) or ASTM D6323–98 (2003) (for biomass)(IBR, see § 63.14(b)) or equivalent.
	b. Composite fuel samples	Procedure in § 63.7521(d) or equivalent.
	c. Prepare composited fuel samples	SW–846–3050B (for solid samples) or SW– 846–3020A (for liquid samples) or ASTM D2013–01 (for coal)(IBR, see § 63.14(b)) or ASTM D5198–92 (2003)(for biomass)(IBR,see § 63.14(b)) or equivalent.
	d. Determine heat content of the fuel type	ASTM D5865–03a (for coal)(IBR, see § 63.14(b)) or ASTM E 711–87 (for biomass)(IBR, see § 63.14(b)) or equivalent.
	e. Determine moisture content of the fuel type	ASTM D3173–02 (IBR, see § 63.14(b)) or ASTM E871 (IBR, see § 63.14(b)) or equivalent.
	f. Measure mercury concentration in fuel sample.	SW–846–6010B or ASTM D3683–94 (2000) (for coal) (IBR, see § 63.14(b)) or ASTM E885–88 (1996) (for biomass)(IBR, see § 63.14(b)).
	g. Convert concentrations into units of pounds of pollutant per MMBtu of heat content.	
3. Hydrogen chloride	a. Collect fuel samples	Procedure in § 63.7521(c) or ASTM D2234 □1 (for coal)(IBR, see § 63.14(b)) or ASTM D6323–98 (2003) (for biomass)(IBR, see § 63.14(b)) or equivalent.
	b. Composite fuel samples	Procedure in § 63.7521(d) or equivalent.
	c. Prepare composited fuel samples	SW–846–3050B (for solid samples) or SW– 846–3020A (for liquid samples) or ASTM D2013–01 (for coal)(IBR, see § 63.14(b)) or ASTM D5198–92 (2003) (for biomass)(IBR, see § 63.14(b)) or equivalent.
	d. Determine heat content of the fuel type	ASTM D5865–03a (for coal)(IBR, see § 63.14(b)) or ASTM E711–87 (1996) (for biomass)(IBR, see § 63.14(b)) or equivalent.
	e. Determine moisture content of the fuel type	ASTM D3173–02 (IBR, see § 63.14(b)) or ASTM E871–82 (1998)(IBR, see § 63.14(b)) or equivalent.
	f. Measure mercury concentration in fuel sample.	SW–846–9250 or ASTM E776–87 (1996) (for biomass)(IBR, see § 63.14(b)) or equivalent.
	g. Convert concentrations into units of pounds of pollutant per MMBtu of heat content.	

TABLE 7 TO SUBPART DDDDD OF PART 63—ESTABLISHING OPERATING LIMITS

As stated in § 63.7520, you must comply with the following requirements for establishing operating limits:

If you have an applicable emission limit for	And your operating limits are based on	You must	Using	According to the following requirements
1. Particulate matter, mercury, or total selected metals.	a. Wet scrubber operating parameters.	i. Establish a site-specific minimum pressure drop and minimum flow rate operating limit according to § 63.7530(c).	(1) Data from the pressure drop and liquid flow rate monitors and the particulate matter, mercury, or total selected metals performance test.	(a) You must collect pressure drop and liquid flowrate data every 15 minutes during the entire period of the performance tests; (b) Determine the average pressure drop and liquid flow-rate for each individual test run in the three-run performance test by computing the average of all the 15-minute readings taken during each test run.
	b. Electrostatic precipitator operating parameters (option only for units with additional wet scrubber control).	i. Establish a site-specific minimum voltage and secondary current or total power input according to § 63.7530(c).	(1) Data from the pressure drop and liquid flow rate monitors and the particulate matter, mercury, or total selected metals performance test.	(a) You must collect voltage and secondary current or total power input data every 15 minutes during the entire period of the performance tests; (b) Determine the average voltage and secondary current or total power input for each individual test run in the three-run performance test by computing the average of all the 15-minute readings taken during each test run.
2. Hydrogen Chloride	a. Wet scrubber operating parameters.	i. Establish a site-specific minimum pressure drop and minimum flow rate operating limit according to § 63.7530(c).	(1) Data from the pH, pressure drop, and liquid flow-rate monitors and the hydrogen chloride performance test.	(a) You must collect pH, pressure drop, and liquid flow-rate data every 15 minutes during the entire period of the performance tests; (b) Determine the average pH, pressure drop, and liquid flow-rate for each individual test run in the three-run performance test by computing the average of all the 15-minute readings taken during each test run.

TABLE 7 TO SUBPART DDDDD OF PART 63—ESTABLISHING OPERATING LIMITS continued:

As stated in § 63.7520, you must comply with the following requirements for establishing operating limits:

	b. Dry scrubber operating parameters.	i. Establish a site-specific minimum sorbent injection rate operating limit according to § 63.7530(c).	(1) Data from the sorbent injection rate monitors and hydrogen chloride performance test.	(a) You must collect sorbent injection rate data every 15 minutes during the entire period of the performance tests; (b) Determine the average sorbent injection rate for each individual test run in the three-run performance test by computing the average of all the 15-minute readings taken during each test run.

TABLE 8 TO SUBPART DDDDD OF PART 63—DEMONSTRATING CONTINUOUS COMPLIANCE

As stated in § 63.7540, you must show continuous compliance with the emission limitations for affected sources according to the following:

If you must meet the following operating limits or work practice standards	You must demonstrate continuous compliance by
1. Opacity	a. Collecting the opacity monitoring system data according to §§ 63.7525(b) and 63.7535; and b. Reducing the opacity monitoring data to 6-minute averages; and c. Maintaining opacity to less than or equal to 20 percent (6-minute average) except for one 6-minute period per hour of not more than 27 percent for existing sources; or maintaining opacity to less than or equal to 10 percent (1-hour block average) for new sources.
2. Fabric Filter Bag Leak Detection Operation	Installing and operating a bag leak detection system according to § 63.7525 and operating the fabric filter such that the requirements in § 63.7540(a)(9) are met.
3. Wet Scrubber Pressure Drop and Liquid Flow-rate	a. Collecting the pressure drop and liquid flow rate monitoring system data according to §§ 63.7525 and 63.7535; and b. Reducing the data to 3-hour block averages; and c. Maintaining the 3-hour average pressure drop and liquid flow-rate at or above the operating limits established during the performance test according to § 63.7530(c).
4. Wet Scrubber pH	a. Collecting the pH monitoring system data according to §§ 63.7525 and 63.7535; and b. Reducing the data to 3-hour block averages; and c. Maintaining the 3-hour average pH at or above the operating limit established during the performance test according to § 63.7530(c).
5. Dry Scrubber Sorbent or Carbon Injection Rate	a. Collecting the sorbent or carbon injection rate monitoring system data for the dry scrubber according to §§ 63.7525 and 63.7535; and b. Reducing the data to 3-hour block averages; and c. Maintaining the 3-hour average sorbent or carbon injection rate at or above the operating limit established during the performance test according to §§ 63.7530(c).
6. Electrostatic Precipitator Secondary Current and Voltage or Total Power Input.	a. Collecting the secondary current and voltage or total power input monitoring system data for the electrostatic precipitator according to §§ 63.7525 and 63.7535; and b. Reducing the data to 3-hour block averages; and c. Maintaining the 3-hour average secondary current and voltage or total power input at or above the operating limits established during the performance test according to §§ 63.7530(c).
7. Fuel Pollutant Content	a. Only burning the fuel types and fuel mixtures used to demonstrate compliance with the applicable emission limit according to § 63.7530(c) or (d) as applicable; and b. Keeping monthly records of fuel use according to § 63.7540(a).

TABLE 9 TO SUBPART DDDDD OF PART 63.—REPORTING REQUIREMENTS

As stated in § 63.7550, you must comply with the following requirements for reports:

You must submit a(n)	The report must contain	You must submit the report
1. Compliance report	a. Information required in § 63.7550(c)(1) through (11); and b. If there are no deviations from any emission limitation (emission limit and operating limit) that applies to you and there are no deviations from the requirements for work practice standards in Table 8 to this subpart that apply to you, a statement that there were no deviations from the emission limitations and work practice standards during the reporting period. If there were no periods during which the CMSs, including continuous emissions monitoring system, continuous opacity monitoring system, and operating parameter monitoring systems, were out-of-control as specified in § 63.8(c)(7), a statement that there were no periods during which the CMSs were out-of-control during the reporting period; and c. If you have a deviation from any emission limitation (emission limit and operating limit) or work practice standard during the reporting period, the report must contain the information in § 63.7550(d). If there were periods during which the CMSs, including continuous emissions monitoring system, continuous opacity monitoring system, and operating parameter monitoring systems, were out-of-control, as specified in § 63.8(c)(7), the report must contain the information in § 63.7550(e); and d. If you had a startup, shutdown, or malfunction during the reporting period and you took actions consistent with your startup, shutdown, and malfunction plan, the compliance report must include the information in § 63.10(d)(5)(i)	Semiannually according to the requirements in § 63.7550(b).
2. An immediate startup, shutdown, and malfunction report if you had a startup, shutdown, or malfunction during the reporting period that is not consistent with your startup, shutdown, and malfunction plan, and the source exceeds any applicable emission limitation in the relevant emission standard.	a. Actions taken for the event; and	i. By fax or telephone within 2 working days after starting actions inconsistent with the plan; and
	b. The information in § 63.10(d)(5)(ii)	ii. By letter within 7 working days after the end of the event unless you have made alternative arrangements with the permitting authority.

Other Attachments Are Available Upon Request

SENDER: COMPLETE THIS SECTION

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Mr. F. J. Perrett, Environmental Manager
Rayonier Performance Fibers LLC
Fernandina Beach Mill
The Foot of the Gum Tree
Post Office Box 2002
Fernandina Beach, FL 32035-2002

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X Ruth a. Benjamin ☐ Agent ☐ Addressee

B. Received by (*Printed Name*) Ruth a. Benjamin

C. Date of Delivery 2-3-06

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
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Mr. F. J. Perrett, Environmental Manager
Rayonier Performance Fibers LLC
Fernandina Beach Mill
The Foot of the Gum Tree
Post Office Box 2002
Fernandina Beach, FL 32035-2002

PS Form 3800, May 2000 See Reverse for Instructions

Department of Environmental Protection

Jeb Bush
Governor

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

Colleen M. Castille
Secretary

January 26, 2006

CERTIFIED MAIL – Return Receipt Requested

Mr. F. J. Perrett
Environmental Manager
Rayonier Performance Fibers LLC
Fernandina Beach Mill
The Foot of Gum Street
P.O. Box 2002
Fernandina Beach, Florida 32035-1309

RE: Request for Facility Modifications
Air Construction Project No.: 0890004-018-AC

Dear Mr. Perrett:

One copy of the Technical Evaluation and Preliminary Determination, the Public Notice, and the Draft Air Construction Permit for the facility modifications requested for Rayonier Performance Fibers LLC's existing sulfite mill, located at The Foot of Gum Street, Nassau County, is enclosed. The permitting authority's "INTENT TO ISSUE AN AIR CONSTRUCTION PERMIT" and the "PUBLIC NOTICE OF INTENT TO ISSUE AN AIR CONSTRUCTION PERMIT" are also included.

The "PUBLIC NOTICE OF INTENT TO ISSUE AN AIR CONSTRUCTION PERMIT" must be published as soon as possible. Proof of publication, i.e., newspaper affidavit, must be provided to the permitting authority's office within 7 (seven) days of publication pursuant to Rule 62-110.106(5), F.A.C. Failure to publish the notice and provide proof of publication within the allotted time may result in the denial of the permits pursuant to Rule 62-110.106(11), F.A.C.

Please submit any written comments you wish to have considered concerning the permitting authority's proposed action to Jeffrey F. Koerner, P.E., at the above letterhead address. If you have any other questions, please contact Bruce Mitchell at 850/413-9198.

Sincerely,

Trina L. Vielhauer

Trina L. Vielhauer
Chief
Bureau of Air Regulation

TLV/jfk/bm

Enclosures

P.E. CERTIFICATION STATEMENT

PERMITTEE

Rayonier Performance Fibers LLC
Fernandina Beach Dissolving Sulfite Pulp Mill
Nassau County, Florida

Draft Air Permit No. 0890004-018-AC
Power Boiler Replacement Project
No. 6 Batch Digester Increase

PROJECT DESCRIPTION

The applicant requests that the digester production limit be increased from 153,205 to 162,000 ADMT per year. At a later date, the applicant intends to install a blow heat recovery system on the vent from the cooking process, which accounts for approximately 80% of the volatile organic compounds (VOC) generated from the bleaching system. The blow heat recovery system will remove approximately 60% of the VOC emissions from the cooking process vent. After the blow heat recovery system is installed, the applicant requests that the production limit be increased from 162,000 to 175,000 ADMT per year. Minor equipment changes and additions are necessary to realize the increased production levels.

The applicant also proposes to permanently shut down Power Boiler Nos. 1 – 3 and install a new bubbling bed boiler (Power Boiler No. 6) with a maximum heat input rate of 525 MMBtu per hour (450 MMBtu per hour, annual average). The new unit will primarily fire bark/wood, tire-derived fuel (TDF) as a supplemental fuel, and No. 6 residual oil as a startup and supplemental fuel. Also, small amounts of on-specification used oil generated on site will be fired for energy recovery. The "new" unit will be a refurbished coal-fired boiler with the following controls: settling chamber (ash hopper); 4-field electrostatic precipitator (ESP); alkaline wet scrubber; staged combustion; flue gas recirculation (FGR); and the capability to add Selective Non-Catalytic Reduction (SNCR) as necessary to comply with the requested NOx standard. The boiler will be subject to NSPS Subpart D, NESHAP Subpart DDDDD, Rule 62-296.410, F.A.C., and emissions caps (CO, NOx, SO_2) pursuant to Rule 62-212.400(2)(g), F.A.C. (Relaxation).

The application is structured such that potential emissions from the "new" boiler net out of PSD preconstruction review due to the shutdown of the old power boilers. The combined projects net out of PSD preconstruction review based on the planned installation of additional pollution controls, requested emissions caps, and the applicant's projected actual emissions. In addition to the applicable regulations, the draft permit includes several conditions to provide reasonable assurance. See the attached Technical Evaluation and Preliminary Determination for a full discussion of the project.

I HEREBY CERTIFY *that the air pollution control engineering features described in the above referenced application and subject to the proposed permit conditions provide reasonable assurance of compliance with applicable provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Chapters 62-4 and 62-204 through 62-297. However, I have not evaluated and I do not certify aspects of the proposal outside of my area of expertise (including, but not limited to, the electrical, mechanical, structural, hydrological, geological, and meteorological features).*

Jeffery F. Koerner — 1-26-06

Jeffery F. Koerner, P.E. (Date)
Registration Number: 49441

TECHNICAL EVALUATION
&
PRELIMINARY DETERMINATION

PROJECT

Draft Air Construction Permit No. 0890004-018-AC
New Power Boiler No. 6 and Digester No. 6 Project

COUNTY

Nassau County, Florida

APPLICANT

Rayonier Performance Fibers LLC
Fernandina Beach Dissolving Sulfite Pulp Mill
ARMS Facility ID No. 0890004

PERMITTING AUTHORITY

Florida Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation
Air Permitting North Program

January 25, 2006

{Filename: TEPD - Rayonier}

1. GENERAL PROJECT INFORMATION

Facility Description and Location

The applicant operates an existing Dissolving Sulfite Pulp Mill (SIC No. 2611) in Fernandina Beach at the Foot of Gum Street in Nassau County, Florida 32305. The UTM coordinates are Zone 14, 454.7 km East, and 3392.2 km North. This site is in an area that is in attainment (or designated as unclassifiable) for all air pollutants subject to a National Ambient Air Quality Standard (NAAQS).

The mill uses a sulfite (ammonia-base) process to produce various grades of chemical cellulose from pine wood-chips. There are only two other pulp mills located in the United States that produce products similar to the Fernandina Mill and neither of these mills use the same type of manufacturing process. This plant produces approximately 10 different grades of cellulose each with different specifications and customers. The amount of each grade of product that is produced is based on market demand. The cellulose produced at this mill goes into such products as plastics, photographic film, LCD screens, paints, cigarette filters, pharmaceuticals, food products, cosmetics and textiles. Customers of these products have stringent quality requirements. This mill produces approximately 150,000 tons of performance fibers annually.

Existing Process Description

The following process description of the existing facility was provided by the applicant.

The sulfite process utilizes a sulfurous acid and ammonium bisulfite cooking solution to chemically separate the lignin from the cellulose. This is accomplished in six batch pressure vessels called digesters. The "cooking" process requires approximately 6 hours. The pulp and spent cooking solution (SSL – spent sulfite liquor) are separated over vacuum washers called red stock washers. The pulp continues into the screening area while the SSL is pumped to the evaporators. The cooking solution is prepared in the "acid plant". All of the sulfur dioxide which is not captured in the acid making or emitted from the digestion and red stock washer processes is collected and scrubbed in the vent gas scrubber utilizing caustic soda. In this scrubbing tower is a second section for condensing a cooking process by-product, methanol. The methanol is condensed and sent to the effluent treatment system for biological digestion.

Unbleached sulfite pulp from the digesters has un-cooked woody materials called knots and tailings which must be screened from the pulp. Knotters and Cowan screens are utilized to remove these materials. The knots and tailings are collected and pressed for utilization as fuel in the power boilers.

Pulp exiting the screening operation enters the bleach plant. One bleaching stage is called Hot Caustic Extraction (HCE). This is a batch stage utilizing caustic soda to remove small chain cellulose molecules called hemi-cellulose from the pulp. This process uses small pressure vessels called HCE cells. No sulfur compounds are used in this stage. A spent solution washed from the pulp after this stage is called hot caustic extract (HCE) and is sold to kraft mills for its sodium content and energy value. This stage also has methanol as a by product in the vent gas, but presently it is not captured.

Pulp leaving the hot caustic stage is further purified in continuous and batch stages using peroxide, chlorine dioxide, chlorine, sodium hydroxide, and sodium hypochlorite depending on the pulp grade specifications. Following these "bleaching" stages the pulp passes through centrifugal dirt cleaners on the way to the pulp machine. The pulp machine forms the sheet by draining water from pulp slurry containing 99% water over a moving wire to a consistency of 50% water. The remainder of the water is removed by passing the pulp sheet over pressing and drying cylinders heated internally with steam. The sheet is wound on a "jumbo" roll which when completed weighs over 10 tons. The final sheet only has about 7% moisture. No coating occurs on any of the grades produced.

The jumbo rolls are transported to the finishing room where the pulp sheet is cut into smaller rolls or sheets which fit the customers' processes. The finished rolls or bales are shipped to the customer based on their order. No pulp is produced without an order due to the very specific quality requirements and sheet size for each customer.

The digestion, hot caustic extraction stage and pulp machine are high users of steam for heating. The steam is produced in three 1939 vintage power boilers utilizing bark and No. 6 oil for fuel. Steam is also used to produce about 90 percent of the mills electricity needs. The boiler's emissions are cleaned with venturi-type scrubbers.

The spent sulfite liquor (SSL) from the digestion process and the hot caustic extract (HCE) are pumped to the evaporators. From the evaporators the SSL is burned in the recovery boiler. This 1976 boiler provides steam for the evaporators and its emissions are scrubbed for sulfur dioxide removal using an ammonia solution. The ammonium bisulfite produced in the scrubber is used for cooking acid make-up. The emissions are further cleaned with mist filters that remove the ammonium sulfate particulate formed in the scrubber. Methanol from the evaporator vents is piped to condensers which collect the methanol and send it to the biological treatment system.

Regulatory Categories

Title III: The plant is a potential major source of hazardous air pollutants (HAPs).

Title IV: The plant has no units subject to the acid rain provisions of the Clean Air Act.

Title V: The plant is a Title V major source of air pollution in accordance with Chapter 213, F.A.C.

PSD: The plant is a PSD-major facility in accordance with Rule 62-212.400, F.A.C.

NSPS: The plant operates units are subject to New Source Performance Standards in 40 CFR 60.

NESHAP: The plant operates units subject to National Emissions Standards for HAPs in 40 CFR 63.

Project Description

The applicant proposes two changes to the plant:

1. The applicant requests that the digester production limit be increased from 153,205 to 162,000 ADMT per year. At a later date, the applicant intends to install a blow heat recovery system on the vent from the cooking process, which accounts for approximately 80% of the volatile organic compounds (VOC) generated from the bleaching system. The blow heat recovery system will remove approximately 60% of the VOC emissions from the cooking process vent. After the blow heat recovery system is installed, the applicant requests that the production limit be increased from 162,000 to 175,000 ADMT per year. To realize the requested full production level, the applicant proposes to conduct the following work: add a new HCE washer press roll; begin first improvements to pulp machine (drying and head-box); add a new HCE evaporator train; install a new HCE blow heat recovery system to control all HCE cells; add a new HCE cell; install a new HCE washer; begin second improvements to pulp machine (drying and speed increase); and install a new post-HCE washer.

2. The applicant proposes to permanently shut down Power Boiler Nos. 1 – 3 and install a new bubbling bed boiler (Power Boiler No. 6) with a maximum heat input rate of 525 MMBtu per hour (450 MMBtu per hour, annual average). The new unit will primarily fire bark/wood, tire-derived fuel (TDF) as a supplemental fuel, and No. 6 residual oil as a startup and supplemental fuel. Also, small amounts of on-specification used oil generated on site will be fired for energy recovery. The "new" unit will be a refurbished coal-fired boiler with the following controls: settling chamber (ash hopper); 4-field electrostatic precipitator (ESP); alkaline wet scrubber; staged combustion; flue gas recirculation (FGR); and the capability to add Selective Non-Catalytic Reduction (SNCR) as necessary to comply with the requested NOx standard. The application is structured such that potential emissions from the "new" boiler net out of PSD preconstruction review due to the shutdown of the old power boilers.

Therefore, the project affects the proposed new Power Boiler No. 6 and the following existing emissions units: power boilers 1 – 3 (EUs 001, 002, and 003); digesters/pulping system (EU-005), recovery boiler (EU-006), wastewater treatment (WWT) system (EU-010); bleaching system (EU-011), and evaporators (EU-021).

Processing Schedule

09/12/05 Received application for a minor source air pollution construction permit; incomplete.

10/24/05 Received additional information.

11/07/05 Received additional information.

12/19/05 Received additional information.

01/23/06: Received additional information; complete.

2. APPLICABLE REGULATIONS

State Regulations

This project is subject to the applicable environmental laws specified in Section 403 of the Florida Statutes (F.S.). The Florida Statutes authorize the Department of Environmental Protection to establish rules and regulations regarding air quality as part of the Florida Administrative Code (F.A.C.). This project is subject to the applicable rules and regulations defined in the following Chapters of the Florida Administrative Code: 62-4 (Permitting Requirements); 62-204 (Ambient Air Quality Requirements, PSD Increments, and Federal Regulations Adopted by Reference); 62-210 (Permits Required, Public Notice, Reports, Stack Height Policy, Circumvention, Excess Emissions, and Forms); 62-212 (Preconstruction

Review); 62-213 (Title V Air Operation Permits for Major Sources of Air Pollution); 62-296 (Emission Limiting Standards); and 62-297 (Test Methods and Procedures, Continuous Monitoring Specifications, and Alternate Sampling Procedures). Specifically, the proposed project will be subject to the following primary applicable state requirements:

Rule 62-212.400, F.A.C. – Preconstruction Review for the Prevention of Significant Deterioration (PSD) of Air Quality

The Department regulates major air pollution sources in accordance with Florida's Prevention of Significant Deterioration (PSD) program, as defined in Rule 62-212.400, F.A.C. A PSD review is required in areas currently in attainment with the state and federal Ambient Air Quality Standards (AAQS) or areas designated as "unclassifiable" for a given pollutant. A new facility is considered "major" with respect to PSD if it emits or has the potential to emit: 250 tons per year or more of any regulated air pollutant; or 100 tons per year or more of any regulated air pollutant and the facility belongs to one of the 28 PSD Major Facility Categories (Table 62-212.400-1, F.A.C.); or 5 tons per year of lead.

For new projects at existing PSD-major facilities, each regulated pollutant is reviewed for PSD applicability based on emissions thresholds known as the Significant Emission Rates listed in Table 62-212.400-2, F.A.C. Pollutant emissions from the proposed project exceeding these rates are considered "significant" and the applicant must employ the Best Available Control Technology (BACT) to minimize emissions of each such pollutant and evaluate the air quality impacts. Although a facility may be *major* with respect to PSD for only one regulated pollutant, it may be required to install BACT controls for several *significant* regulated pollutants. The current project is proposed at an existing PSD-major facility. PSD applicability to the project will be discussed in the next section.

Rule 62-296.410, F.A.C. - Carbonaceous Fuel Burning Equipment

This rule regulates emissions of particulate matter and opacity from carbonaceous fuel burning equipment. Proposed Power Boiler No. 6 was originally constructed in 1983 and had the capability of firing bark/wood. For purposes of this rule, an "existing unit" is an emissions unit which was in existence, in operation, or under construction, or had received a permit to begin construction prior to January 18, 1972. Therefore, Power Boiler No. 6 will be considered a "new" boiler subject to Rule 62-296.410, F.A.C.

62-296.406, F.A.C. - Fossil Fuel Fired Steam Generators with a Maximum Heat Input Rate of 250 MMBtu/hour

This rule regulates NOx, PM, SO_2, and opacity from fossil fuel fired steam generators with a maximum heat input rate of 250 MMBtu per hour. Proposed Power Boiler No. 6 was originally constructed in 1983 and had a maximum fossil fuel heat input rate of 540 MMBtu per hour. For purposes of this rule, an "existing unit" is an emissions unit which was in existence, in operation, or under construction, or had received a permit to begin construction prior to January 18, 1972. Therefore, Power Boiler No. 6 will be considered a "new" boiler subject to Rule 62-296.406, F.A.C. The rule establishes the emissions standards specified in NSPS Subpart D as the applicable standards.

Federal Regulations

The facility is subject to applicable federal provisions regarding air quality as established by the EPA in the Code of Federal Regulations (CFR). In general, these regulations establish either New Source Performance Standards (NSPS) for new, modified or reconstructed units or National Emissions Standards for Hazardous Air Pollutants (NESHAP) for existing, new, or reconstructed units. Existing units at the facility are subject to portions of the following regulations in 40 CFR 63: Subpart A (General Provisions); Subpart S (NESHAP for Pulp and Paper Industry); Subpart MM (NESHAP for Chemical Recovery Combustion Sources at Kraft, Soda, Sulfite, and Stand-Alone Semi chemical Pulp Mills); and Subpart DDDDD (Industrial, Commercial and Institutional Boilers and Process Heaters). The proposed project will not change the regulated status of any existing unit. New Power Boiler No. 6 will be subject to the applicable requirements of NSPS Subpart DDDDD for existing units as described under the separate section of this report.

3. PSD APPLICABILITY REVIEW FOR PROJECT

Plant History

In the late 1990's, a digester exploded at the Stone Container Mill in Panama City, Florida. The pulp and paper industry began a program to inspect and repair (as necessary) each digester at existing plants to ensure overall safety. In 1998, the Department allowed Rayonier to install a sixth digester to allow the plant to meet current contracts while one digester was shut down for inspection and repair.

Several years later in 2002, the Department issued an after-the-fact air construction permit (No. 0890004-010-AC) that limited plant production to 153,205 air-dried metric tons (ADMT) per year, which identified the capacity of approximately 5 active digesters. Specific Condition 4 of the permit states, "If there is any increase in annual pulp production (153,205

ADMT/year) by the batch digesters, Nos. 1 thru 6, then PSD New Source Review pursuant to Rule 62-212.400(5), F.A.C., shall apply to all major SO_2 emissions units at the facility." Specific Condition 5 of the permit effectively limits SO_2 emissions from the vent gas scrubber system to 276.82 tons per year. This scrubber controls the digesters, vents from the cooking acid plant, red stock washers, unwashed stock tank, spent sulfite liquor storage tanks, spent sulfite washer area, and the blow pits. Emissions from the scrubber are monitored by CEMS. So, the intent of the restriction was to provide an opportunity for a PSD review related to increased SO_2 emissions from the additional digester activity.

The plant is now subject to NESHAP Subpart S in 40 CFR 63. In accordance with the MACT requirements, a condenser/scrubber system was installed in 2001 to reduce methanol (HAP) emissions from the pulping operation. The condenser/scrubber system also reduces VOC and SO_2 emissions.

Regulatory Background

The applicability of PSD preconstruction review for a given project is defined in Rule 62-212.400, F.A.C. (Prevention of Significant Deterioration of Air Quality) and Rule 62-210.200, F.A.C. (Definitions). Florida's PSD preconstruction review program is currently based on EPA's original program, which compares past actual emissions to future potential emissions when determining whether an emissions increase will occur. Subsequent to a 1990 court decision (WEPCO Decision), EPA revised the federal PSD program for electric utility steam generating units to allow a comparison of past actual emissions to future representative actual emissions when determining whether an emissions increase will occur. Florida's current PSD program includes this provision for electric utility steam generating units. In 2002, EPA again revised the federal PSD regulations to allow all industries to compare baseline actual emissions to projected actual emissions when determining whether an emissions increase will occur. Florida has proposed revised rules to incorporate this change. The proposed rule changes will be finalized before the final permit for this project is issued.

Applicant's Review

Digester Project

Fully utilizing the additional capacity of existing Digester No. 6 in the digester/pulping system will also require minor changes to the bleaching system, evaporators, and the WWT system. The existing recovery boiler does not require any physical changes, operational changes, or permit revisions to accommodate any increase in digester production. The permitted capacity of the recovery boiler is 70,000 lb/hour of spent sulfite liquor (SSL). The recovery boiler has repeatedly demonstrated compliance at this level. In 2003 and 2004, the recovery boiler operated at an average SSL burning rate of 68,000 lb/hour for more than 500 hours. The applicant maintains that the current permitted SSL burning rate is sufficient to address any future demand growth up to the requested production level. The unit has successfully operated at this maximum level and demonstrated compliance at this level. The applicant notes that the Department's proposed New Source Review Reform regulations state the following:

"(215) Projected Actual Emissions - The maximum annual rate, in tons per year, 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 design capacity or its 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 major stationary source. One year is one 12-month period. In determining the projected actual emissions, the Department:

(a) Shall consider all relevant information, including historical operational data, the company's own representations, the company's expected business activity and the company's highest projections of business activity, the company's filings with the State or Federal regulatory authorities, and compliance plans or orders, including consent orders; and

(b) Shall include fugitive emissions to the extent quantifiable and emissions associated with startups and shutdowns; and

(c) 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 product demand growth; or

(d) In lieu of using the method set out in paragraphs (a) through (c) above, may be directed by the owner or operator to use the emissions unit's potential to emit, in tons per year."

The requested digester production increase is related to an anticipated increase in market demand for the industry. Production at the Fernandina Beach plant is limited to advance orders because of the unique specifications placed on the specialty fibers requested by each customer. Three similar plants in the United States have recently closed and a fourth is planning to close in 2006. The proposed changes to the digester operations will allow the plant to respond to this anticipated growth in demand for their products.

For SO_2 emissions, the applicant estimated baseline actual SO_2 emissions (2002/2003) from the recovery boiler of 836 tons per year and projected actual emissions of 1073 tons per year at full production after changes to the digester operations. The permitted allowable SO_2 emissions are 1409.92 tons per year. However, the applicant notes that any emissions increases from recovery boiler would be due to "*demand growth*" realized after the digester project. Based on the Department's proposed rules, the emissions increases from the recovery boiler may be excluded from the projected actual emissions because the unit is fully capable of accommodating the additional production without any physical, operational, or permitting changes. Excluding the difference in emissions due to future demand growth would show no emissions increases from the recovery boiler. Therefore, the project to fully utilize the digester production capacity will only affect the following existing emissions units that are actually undergoing a change: digesters/pulping system; bleaching system; evaporators; and the WWT system.

Prior to adding the 6th digester in 1998, the actual annual production was 149,957 ADMT/year in 1996 and 149,426 in 1997. The applicant used the 1996 level of production to calculate the percent increase based on the request to increase production to 162,000 ADMT/year (8% increase) and eventually to 175,000 ADMT/year (16.7% increase). The following table summarizes the emissions from the digester production increase.

Table 3A. Digester Production Increase – Applicant's PSD Netting Analysis

Unit	Summary of Net Emissions Increases (Tons/Year) [a]		
	CO	SO_2	VOC [b]
Digesters/Pulping System	---	10.9	2.9 / 6.1
Bleaching System	25.1	---	14.2 / (-41.5)
Evaporators	---	---	4.3 / 9.0
WWT System	---	---	5.3 / 11.1
Total Net Change	25	11	27 / (-15)
PSD Significant Emissions Rate	100	40	40 / 40
Subject to PSD Review?	No	No	No / No

a. Except for VOC, emissions increases are based on the full 16.7% production increase.

b. For VOC, the first figure identifies future projected actual emissions based on an 8% production increase (162,000 ADMT/year) with no control from the proposed blow heat recovery system. The second figure considers the full 16.7% digester production increase (175,000 ADMT/year), but includes the proposed HCE blow heat recovery system on the bleaching plant to conservatively reduce VOC emissions by approximately 60%.

c. Applicant based emission increases on projected actual emissions resulting from the requested production increase.

Boiler Replacement Project

The applicant is also proposing to replace the existing three power boilers with a single new power boiler primarily due to excessive maintenance and repair costs for the older units. In addition, the proposed bubbling bed power boiler will allow the plant to fire bark/wood available from the plant as the primary fuel, which will reduce operating costs. The applicant views the two projects as separate and distinct projects that should be reviewed independently. The boiler replacement project considers the shutdown of Power Boiler Nos. 1 – 3 (EUs 001 – 003) as emissions decreases and the new Power Boiler No. 6 as emissions increases. As shown in the following table, the applicant concludes that the boiler replacement project will net out of PSD preconstruction review when considered as a separate project.

Table 3B. Boiler Replacement Project – Applicant's PSD Netting Analysis

Unit	Summary of Net Emissions Increases (Tons/Year)					
	CO	NOx	PM	PM_{10}[b]	SO_2	VOC
Baseline (Power Boilers 1 – 3)	(-690.8)	(-341.0)	(-276.1)	(-242.5)	(-182.0)	0[a]
Proposed Power Boiler No. 6	394.2	380.0	138.0	138	210.0[d]	3.9
Total Net Change	(-297)[c]	39	(-138)	(-105)	28	3.9
PSD Significant Emissions Rate	100	40	25	15	40	40
Subject to PSD Review?	No	No	No		No	No

Notes:

a. Applicant estimates ~ 45 tons per year from the old units, but assumed "0" because it is difficult to determine.

b. Applicant's estimation for PM_{10}.

c. Substituted applicant's potential annual CO emission rate (394.2 tons/year) identified in the application form, which was higher than identified in applicant's netting summary.

d. Applicant's information provided on 12/19/05 incorrectly included 10.9 tons/year of SO2 increases from the 16.7% production increase. Accordingly, the requested cap on SO2 emissions was adjusted down to 210 tons/year.

Applicant's Conclusion

Based on the separate project reviews presented, the applicant concludes that neither the boiler replacement project nor the digester production increase project is subject to PSD preconstruction review.

Department's Review

Digester Project

The digester project requires changes for the following affected units: bleaching system, evaporators, and wastewater (WWT) treatment system. CO and SO_2 emissions increases from these units will be minimal. Actual VOC emissions increases could exceed the PSD significant emissions rate of 40 tons/year with the full production increase to 175,000 ADMT/year. However, the plant will restrict production to 162,000 AMDT/year or less until HCE blow heat recovery system is installed, which will reduce actual emissions of methanol, VOC, and SO_2 emissions. Once the HCE blow heat recovery system is installed and satisfactorily tested, the plant may operate at full production capacity (175,000 AMDT/year) because this system will actually result in a decrease in VOC emissions and not an increase.

With regard to consideration of the recovery boiler, this project includes the following unique factors:

- There are 6 existing active digesters at this plant. Due to an industrial accident at another Florida plant, the Department allowed the installation of the 6th digester in 1998 as a safety/maintenance project. An after-the-fact air construction permit (Permit No. 0890004-010-AC) was issued in 2002 with a digester/pulping system production limit of 153,205 ADMT per year to ensure that the installation of the 6th digester did not allow a PSD-significant emissions increase for SO_2 without a PSD applicability review. The proposed project would relax this limit and requires a PSD applicability review for SO_2 emissions in accordance with Condition No. 4 in Permit No. 0890004-010-AC.
- To realize the increased production capacity, only minor physical and/or operational changes are needed for the digester/pulping system, bleaching system, evaporators, and the WWT system. The permittee will also install an additional condenser scrubber to remove methanol, SO_2, and VOC emissions prior increasing operations to full capacity (175,000 ADMT per year). These are all affected units.
- In 2000, SO_2 emissions from the pulping operation were approximately 70 tons/year. A condenser/scrubber system was installed in 2001 to reduce methanol (HAP) emissions from the pulping operation pursuant to NESHAP Subpart S. Combined with a revamped scrubber system SO_2 emissions were also reduced. In 2004, estimated SO_2 emissions from the pulping operation were approximately 11 tons per year. Assuming a 16.7% increase from 2004 emissions, SO_2 emissions would increase approximately 2 tons/year from the pulping operation.
- The current Title V permit specifies the following capacity of the recovery boiler and SO_2 limits: 70,000 lb/hour of

spent sulfite liquor (SSL); 321.9 lb of SO_2/hour and 1409.92 tons of SO_2/year.

- Plant records show that the recovery boiler operated near this permitted capacity for over 570 periods based on 48-hour moving averages during the 2003 – 2004 operating years. Records also indicate that the recovery boiler has demonstrated compliance near this specified capacity. No physical, operational, or permitting changes to the recovery boiler are necessary to accommodate any increase in digester production.
- The Department also reviewed previous Annual Operating Reports to compare past SO_2 emissions from the recovery boiler with past production levels from 1995 through 2004, as summarized in the following table.

Year	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
Production, ADMT/Yr	143,953	149,957	149,426	132,016	119,689	151,515	146,247	145,895	144,975	145,883
SO_2, TPY	1097	1087	1149	929	950	1067	829	1075	876	797
lb SO_2 per ADMT	15.2	14.5	15.4	14.1	15.9	14.1	11.3	14.7	12.1	10.9

The above table shows that there is not a direct, linear correlation between production and SO_2 emissions from the recovery boiler. There are other important factors influencing emissions such as wood material availability, fuel availability, actual fuel sulfur content, SO_2 removal in the scrubber, etc. The table also shows a general trend of decreasing SO_2 emissions from the recovery boiler. For example, baseline actual SO_2 emissions for 1996/1997 would be 1118 tons/year, which is actually higher than the applicant's projected actual emissions (1073 tons/year) after the proposed project.

- The application was submitted in September of 2005. The Department anticipates a final version of its New Source Review Reform regulations in February of 2006. Under the new regulations, an applicant may compare projected actual emissions to baseline actual emissions from an existing unit. In determining the projected actual emissions, the new regulation states that the Department 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 product demand growth. As indicated above, the recovery boiler is physically capable of accommodating any increase due to demand growth and is not otherwise restricted by permit condition. Based on the proposed regulations, the project would not trigger PSD preconstruction review.

Rule 62-210.200(11)(b), F.A.C. states, "*The Department may presume that unit-specific allowable emissions for an emissions unit are equivalent to the actual emissions of the emissions unit provided that, for any regulated air pollutant, such unit-specific allowable emissions limits are federally enforceable.*" The Department uses this discretion with care and previous instances have been infrequent. However, this project presents unique circumstances as described above, particularly with regard to timing of the pending rule changes which would show no PSD-significant emissions increase. To satisfy current regulations at the time of issuance for the draft permit and acknowledging that the proposed regulations will be in effect when the final permit is issued, the Department presumes actual SO_2 emissions from the recovery boiler to be equivalent to the unit-specific allowable emissions (1409.92 tons/year) before the project as well as after the project. Therefore, there is no increase in SO_2 emissions from the recovery boiler. For purposes of Condition No. 4 in Permit No. 0890004-010-AC increasing the digester production limit to 175,000 ADMT per year will not result in a PSD-significant net SO_2 emissions increase.

Boiler Replacement Project

As shown in the applicant's netting analysis, the new bubbling bed Power Boiler No. 6 is expected to result in actual decreases for CO, PM/PM_{10}, and VOC emissions compared to the old power boilers. CO, NOx and SO_2 emissions from the new boiler will be capped by federally enforceable emissions limits with compliance demonstrated by Continuous Emissions Monitoring Systems (CEMS). The old power boilers are regulated only for PM and SO_2 emissions. The following table provides a comparison of the allowable PM and SO_2 emissions from the existing power boilers to the new replacement power boiler.

Table 3C. Comparison of Allowable Emissions from Boilers

Emissions	Power Boiler 1	Power Boiler 2	Power Boiler 3	Total, 1-3	Power Boiler 6
PM	70.0	212.5	212.5	495.0	138.0
SO_2	1848.0	1756.0	1928.0	1928.0	210.0

Conclusion

The Department also reviewed the state database (ARMS) and found the following three contemporaneous projects permitted within the last 5 years.

- Project No. 080004-014-AC authorized a temporary period to test and calibrate a new type of beta attenuation particulate monitor. The test lasted just a few days and any particulate matter emissions increases would have been quite small. It is also noted that the proposed project will result in a decrease in particulate matter emissions.
- Project No. 080004-015-AC involved the three existing power boilers. However, actual emissions from these units are already presented in the netting table for the current project.
- Project No. 080004-017-AC imposed the new Subpart MM requirements for the recovery boiler and authorized the firing of small amounts of on-specification used oil fuel generated on site. Used oil fuel would displace residual oil and there were no identifiable emissions increases.

Based on the above discussion, only the proposed digester project and the proposed boiler replacement project are contemporaneous. At the Department's request, the applicant provided the following net emissions summary of the combined projects.

Table 3D. Combined PSD Netting Analysis

Unit	Summary of Net Emissions Increases (Tons/Year)					
	CO	NOx	PM	PM10[b]	SO2	VOC[a]
Digester Project	25	0	0	0	11	27
Boiler Replacement Project	(-297)	39	(-138)	(-105)	28	3.9
Total Net Change	(-272)	39	(-138)	(-105)	39	31
PSD Significant Emissions Rate	100	40	25	15	40	40
Subject to PSD Review?	No	No	No	No	No	No

Notes:

a. Applicant assumed worst-case scenario for VOC emissions: digester production level of 162,000 AMDT/year prior to installation of HCE blow heat recovery system. VOC emissions will decrease before the full production level (175,000 ADMT/year) is realized because the HCE blow heat recovery system must be installed on the bleaching plant.

b. Applicant's estimation for PM10.

Based on the above netting analysis that includes contemporaneous emissions increases and decreases, the project is not subject to PSD preconstruction review. The following sections provide additional details of the draft permit.

4. DIGESTER PROJECT REVIEW

Phase I – Production Capacity of 162,000 ADMT per Year

As described below, the applicant indicates that minimal additional equipment will be needed to achieve the 162,000 AMDT/yr production increase requested for this project.

Post-HCE Press Roll

The mill will add a post-HCE washer press roll. There are negligible emissions expected from the press roll because there are no chemical reactions taking place; water is being physically removed from the pulp. The press roll will result in a more uniform pulp consistency from the washer and a higher solids concentration in the HCE liquor transferred from the washer to the HCE evaporators. Although this equipment will improve overall efficiency, it is probably not a necessary addition to achieve the 162,000 ADMT per year production level. However, removing additional moisture in this step will later allow the HCE evaporators to accommodate the full requested production level of 175,000 ADMT per year. Addition of the new press roll is scheduled for 2006.

HCE Evaporators

Three new evaporator modules will be added to form a new evaporator train used to thicken the additional heat caustic extract (HCE) produced by the increase in production. Condensed water from the HCE evaporators may be used as plant process water; otherwise, it will discharge directly to the water treatment plant. Vapors that are not condensed will be directed to the existing 2-stage direct contact condenser (methanol scrubber). The condensed organics from this scrubber are discharged to the wastewater treatment plant.

Wastewater Treatment (WWT) System

VOC emissions stripped to ambient air by the aerators were calculated by the "Water9" estimation software. The emission estimate assumed "no control" from the HCE stage for increasing production to 162,000 ADMT per year.

Pulp Machine

An increase in the pulp machine drying capacity will be required. This will be accomplished by upgrading the dryer can system over which the pulp passes to dry the pulp, which includes: increasing the drying steam pressure inside the cans; installing a new head-box to increase the width of the pulp web across the machine and to improve machine sheet uniformity at higher machine speeds; and upgrading the control and water-addition systems. There are no emissions associated with pulp machine operations because there is no coating and the pulp has been purified to the point there are no remaining organics to emit.

Phase II – Increase Production Capacity to 175,000 ADMT per Year

The applicant proposes to conduct the following additional work to achieve the full requested production capacity of 175,000 ADMT per year, including the installation of a new blow heat recovery system to ensure that the project will not be PSD-significant for VOC emissions.

HCE Cell

To achieve the full requested production level of 175,000 ADMT per year, a new HCE cell will be added to handle the increased volume of pulp. A new blow heat recovery system will be installed to control emissions from this new cell as well as all existing cells. The blow heat recovery system will be installed and operational prior to increasing production beyond the 162,000 ADMT per year rate. Preliminary plans also include an additional washer for the caustic extraction stages to maintain the purity of pulp production at the full production level of 175,000 ADMT per year. This washer would be after release and capture of VOC from the HCE blow heat recovery system and would have no sulfur dioxide or chlorine emissions.

HCE Evaporator Train

Pressing additional moisture from the HCE material will allow the HCE evaporator train to accommodate the capacity increase from 162,000 to 175,000 ADMT per year. As before, condensed water from the HCE evaporators may be used as plant process water; otherwise, it will discharge directly to the water treatment plant. Vapors that are not condensed will be directed to the existing 2-stage direct contact condenser (methanol scrubber). The condensed organics from this scrubber are discharged to the wastewater treatment plant. For the full 175,000 ADMT per year production level, the emission estimates are contingent upon installing the HCE blow heat recovery system to control VOC emissions.

Blow Heat Recovery System

The mill will install a new blow heat recovery system to ensure that the project will not be PSD-significant for VOC emissions. This system will capture blow heat from one of the bleach plant stages that is the most significant source of VOC emissions. The HCE blow heat capture system will be very similar to the systems used on Kraft digesters for the recovery of heat except it will be considerably smaller and there will be no TRS gases because there is no sulfur in the pulp at this stage. The blow gas will be condensed to extract the heat and the condensate will contain VOC from the exhaust of all HCE cells. This condensate will be discharged to the biological wastewater treatment system where it will be biologically destroyed. Emissions from the HCE blow tank have been measured. The reduction in emissions that will be achieved has been estimated at greater than 74% control of HCE blow emissions, although 60% was used in estimating emission reductions.

Pulp Machine

To achieve the full requested production level of 175,000 ADMT per year, the mill plans to further increase drying capacity of the machine by increasing drying steam pressure. Depending on the effectiveness of the initial planned improvements, other pulp machine upgrades may be needed such as: final-sheet cooling; Fourdrinier wire vacuum system improvements; ventilation system upgrades; and drive system enhancements. These are all non-emitting equipment.

Wastewater Treatment (WWT) System

The amount of VOC stripped to the ambient air by the aerators was calculated by the "Water9" estimation software. For the full 175,000 ADMT per year production level, the emission estimates are contingent upon installing the HCE blow heat recovery system to control VOC emissions.

Schedule

The application indicates the following preliminary schedule for commencing construction:

Date	Activity
February 2006	Add a new HCE washer press roll
February 2007	Begin first improvements to pulp machine drying and head-box
	Add a new HCE evaporator train
February 2008	Install a new HCE blow heat recovery system to control all HCE cells
	Add a new HCE cell
	Install a new HCE washer
	Begin second improvements to pulp machine drying and speed increase
	Install a new post-HCE washer

It is noted that some of the later changes are contingent on the success of the earlier stages. New process flow diagrams are shown in Attachment A to this report.

Permit Conditions

The draft permit will include the following conditions related to this project.

- The permittee is authorized to perform the following construction and proposed work: add a new HCE washer press roll (February 2006); begin first improvements to pulp machine drying and head-box (February 2007); add a new HCE evaporator train (February 2007); install a new HCE blow heat recovery system to control all HCE cells (February 2008); add a new HCE cell (February 2008); install a new HCE washer (February 2008); begin second improvements to pulp machine drying and speed increase (February 2008); and install a new post-HCE washer (February 2008). The dates indicated represent the preliminary schedule for construction. The permittee shall obtain prior written approval for any substantial changes to the work described above and in the application for this project.
- Within fourteen (14) days of completing each of the above stages of work, the permittee shall provide a written notice of the following: type of work; date completed; minor deviations form original proposal; and a discussion of any emissions impacts.
- Upon issuance of this permit, plant production shall not exceed 162,000 ADMT per consecutive 12 months, rolling total.
- Prior to increasing plant production beyond 162,000 ADMT per year, the permittee shall install a new HCE blow heat recovery system designed to reduce VOC emissions by 60% from all HCE cells. Upon successful completion of this system, the permittee shall conduct an engineering study to determine the effectiveness of this system in capturing and reducing VOC emissions. Within 60 days of completing the engineering study, the permittee shall submit a report summarizing: the final installed design, material flow rates, emissions, emissions capture, and emissions control.
- Upon successful completion of the new HCE blow heat recovery system and submittal of the required engineering report, plant production shall not exceed 175,000 ADMT per consecutive 12 months, rolling total.
- Attached to each required Annual Operating Report, the permittee shall provide a summary of the following to the compliance authority: a summary of work performed to date; a summary of work remaining; a preliminary schedule for completing any remaining work; and the current production capacity of the mill (ADMT per year).

5. REPLACEMENT BOILER PROJECT REVIEW

Description of Boiler, Fuels and Controls

The applicant proposes to permanently shut down Power Boiler Nos. 1 – 3 and install a new bubbling bed boiler, Power Boiler No. 6. The proposed "new" boiler is a 1982 Combustion Engineering Model CE VU-40 traveling grate boiler that will be converted to a bubbling fluidized bed boiler. Initial startup of the boiler is scheduled for the end of 2006 or early 2007. It will be located adjacent to the digesters east of the mill. Once constructed and fully operational, it will be connected to the mill steam headers and the existing power boilers will cease operation and be permanently shut down. Power Boiler No. 6 and the recovery boiler will be the sole steam producers used by the mill. Eventually, the existing power boilers will be dismantled.

The design steam conditions will be 900 psig and 875° F. The maximum continuous steam production rate (24-hour average) will be 310,000 lb/hour (525 MMBtu/hour heat input). The maximum annual steam production capacity of Power Boiler No. 6 will restricted to 265,000 lb/hour based on a 12-month rolling average (450 MMBtu/hour heat input). Power Boiler No. 6 will fire the following fuels.

- Bark/Wood (SCC No. 10100901): The boiler will fire bark, wood knots, and side-hill fines recovered as process byproducts. This fuel has a heating value of approximately 9 MMBtu/ton burned (wet, as fired). Bark contains approximately 50% moisture and 0.03% sulfur by weight. Wood knots and side-hill fines contain approximately 50-60% moisture and 0.4% sulfur by weight. Based on these characteristics, the maximum boiler firing rate would be 52 tons of bark/wood per hour and, of this amount, only about 5 tons per hour would come from wood knots and side-hill fines. The maximum annual bark/wood firing would be 451,425 tons per year.
- Tire-Derived Fuel (SCC No. 10100801): Tire-derived fuel (TDF) may be fired as a supplemental fuel. This fuel has a heating value of approximately 31 MMBtu/ton burned (as fired). TDF contains less than 1% moisture and approximately 1.85% sulfur by weight. TDF would be co-fired with bark/wood at a maximum rate hourly rate of 3 tons of TDF per hour and at a maximum annual rate of 26,159 tons per year (approximately 20% of the annual average heat input rate).
- No. 6 Fuel Oil (SCC No. 10100401): No. 6 fuel oil will be fired as a supplemental fuel and may include small amounts of on-specification used oil generated on site. Fuel oil will contain a maximum of 2.5% sulfur by weight. Based on a heating value of 150 MMBtu/thousand gallons burned, the maximum hourly oil firing rate will be 1400 gallons per hour and the maximum annual firing rate will be 11,927,000 gallons per year.

During the boiler conversion, the boiler furnace will be lengthened to increase flue gas residence time and provide staged combustion to inhibit NOx formation. CO and VOC emissions are expected to be minimal at 0.25 lb/MMBtu of heat input (vendor guarantee) and 0.002 lb/MMBtu of heat input (test on similar B&W unit), respectively. The converted boiler will also include flue gas recirculation (FGR) to lower NOx emissions. The applicant expects relatively low NOx emissions from this unit after the conversion. However, the original boiler includes a selective non-catalytic reduction (SNCR) system to control NOx emissions. Due to some uncertainty of the emissions characteristics after the boiler conversion, the applicant may install this equipment after initial startup to comply with the emissions standards and caps.

An SNCR system generally consists of an ammonia tank, pumps, piping, compressed air delivery, injectors, and a control system. In the SNCR process, ammonia or urea is injected into a high-temperature region without a catalyst to reduce NOx emissions to nitrogen and water vapor. The temperature region is typically maintained above 1600° F to allow the reaction to occur; otherwise the NOx reduction will be minimal and unreacted ammonia (slip) will be emitted. Also, the exhaust temperature must not exceed 2000° F or ammonia will actually be oxidized creating additional NOx emissions. For biomass-fired boilers, SNCR can reduce NOx emissions by up to 50% or more.

Particulate matter emissions are removed from the boiler exhaust with a large setting chamber followed by an electrostatic precipitator (ESP). Large ash particles settle out in the chamber and are removed from the bottom hopper by a screw conveyor system. The four-field ESP design will include collector plates with rigid electrodes. Each field will have a dedicated transformer/rectifier (T/R) set and ash hopper. Ash will be removed by a screw conveyor system. The applicant plans to install an opacity monitor following the ESP, but before the scrubber to indicate satisfactory operation of the ESP. Although the designed system is to result in greater than 99% reduction of particulate matter emissions, the applicant requests a PM emission standard of 0.07 lb/MMBtu of heat input based on NESHAP Subpart DDDDD standards for existing units and PSD netting requirements.

An induced draft fan is located between the ESP and the wet scrubber with stack. The wet scrubber will spray approximately 4000 gpm of re-circulated alkaline scrubber water over a series of chevrons and louver-type packings to reduce SO_2 emissions. The design pressure drop across the system will be approximately 2 inches of water column. The wet scrubber will remove approximately 90% or more of SO_2 emissions under maximum operating conditions. The alkalinity of the ash formed from wood combustion is also expected to capture some SO_2 emissions. Emissions exhaust at a volumetric flow rate of 183,421 acfm and a temperature of 150° F through the wet single scrubber stack that is 10 feet in diameter and 190 feet above ground level.

Primary Applicable Requirements

NSPS Subpart Db Applicability

For new Power Boiler No. 6, the applicant proposes to modify an existing traveling grate coal-fired boiler into a bubbling bed boiler as part of this project. The existing coal-fired boiler was originally constructed in 1983 at the Stone Container Panama City Mill subject to the applicable requirements in NSPS Subpart D of 40 CFR 60 for industrial boilers. The maximum heat input rate was 540 MMBtu/hour (397 MMBtu/hour from coal and 143 MMBtu/hour from bark). In 1989, EPA promulgated NSPS Subpart Db of 40 CFR 60 for industrial boilers constructed, modified or reconstructed after June 19, 1984.

The proposed Power Boiler No. 6 will have a maximum heat input rate of 525 MMBtu/hour (315 MMBtu/hour from oil and 210 MMBtu/hour from bark) and is not considered a "new" unit as defined in NSPS Subpart Db. To be considered a "modified" boiler, the maximum emissions rate of a regulated pollutant must increase. Subpart Db regulates nitrogen oxides, particulate matter, and sulfur dioxide. The following table compares the regulated emissions as originally constructed and after conversion to a bubbling bed boiler. As shown, the Power Boiler No. 6 is not considered a modified unit subject to NSPS Subpart Db.

NSPS Subpart Db Applicability - Modification

Pollutant	Original		Converted		Modified?
	lb/MMBtu	lb/hour	lb/MMBtu	lb/hour	
NOx	0.3	162.0	0.3	157.5	No
PM	0.1	54.0	0.07	36.8	No
SO_2 – solid fossil fuel	1.2	476.4	NA	NA	NA
SO_2 – liquid fossil fuel	0.8	NA	0.8	168.0	No

A boiler is considered "reconstructed" if the cost of the replacement components exceed 50% of the fixed capital cost that would be required to construct a comparable new unit. Based on an engineering quote by the Kaeverner Corporation, it is estimated that a comparable new unit would cost approximately $40 million. Based on a vendor quote, it is estimated that the cost of replacement components to convert the existing unit to a bubbling bed boiler would be approximately $14 million. As this represents only 35% of the fixed capital costs of a comparable new unit, the boiler is not considered a reconstructed unit subject to NSPS Subpart Db.

NSPS Subpart D Applicability

The primary applicable requirements from NSPS Subpart D are summarized below.

§ 60.42 Standard for Particulate Matter

PM $\leq$ 0.10 lb/MMBtu derived from fossil fuel or fossil fuel and wood residue

Opacity $\leq$ 20% except for one 6-minute period per hour of not more than 27%

§ 60.43 Standard for Sulfur Dioxide

$SO_2 \leq$ 0.80 lb/MMBtu (3-hour average) derived from liquid fossil fuel or liquid fossil fuel and wood residue

§ 60.44 Standard for Nitrogen Oxides

NOx $\leq$ 0.30 lb per million Btu (3-hour average) derived from liquid fossil fuel or liquid fossil fuel and wood residue

§ 60.45 Emission and Fuel Monitoring

(a) Each owner or operator shall install, calibrate, maintain, and operate continuous monitoring systems for measuring the opacity of emissions, sulfur dioxide emissions, nitrogen oxides emissions, and either oxygen or carbon dioxide except as provided in paragraph (b) of this section.

(g) Excess emission and monitoring system performance reports shall be submitted to the Administrator semiannually for each six-month period in the calendar year. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period. Each excess emission and MSP report shall include the information required in Sec. 60.7(c). Periods of excess emissions and monitoring systems (MS) downtime that shall be reported are defined as follows:

(1) Opacity. Excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 20 percent opacity, except that one six-minute average per hour of up to 27 percent opacity need not be reported.

(2) Sulfur Dioxide. Excess emissions for affected facilities are defined as:

(i) Any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of sulfur dioxide as measured by a continuous monitoring system exceed the applicable standard under Sec. 60.43.

(3) Nitrogen Oxides. Excess emissions for affected facilities using a continuous monitoring system for measuring nitrogen oxides are defined as any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards under Sec. 60.44.

NESHAP Subpart DDDDD Applicability - New Power Boiler No. 6

NESHAP Subpart DDDDD applies to new, reconstructed, or existing industrial boilers. A new boiler is one that is constructed after January 13, 2003. Similar to the NSPS requirements, a boiler is considered "reconstructed" if the cost of the replacement components exceed 50% of the fixed capital cost that would be required to construct a comparable new unit. An industrial boiler that is neither new nor reconstructed is considered an existing unit.

For the subpart, "large solid fuel subcategory" includes any water-tube boiler or process heater that burns any amount of solid fuel either alone or in combination with liquid or gaseous fuels, has a rated capacity of greater than 10 MMBtu per hour heat input, and has an annual capacity factor of greater than 10 percent. Therefore, the converted Power Boiler No. 6 is subject to the applicable requirements of NSPS Subpart DDDDD as an existing, large solid fuel fired units.

The application indicates that Power Boiler No. 6 will comply with the Subpart DDDDD requirements by installing an electrostatic precipitator and an alkaline wet scrubber. The unit will be tested to demonstrate compliance with the emissions limits and work practice standards for particulate matter (in lieu of total selected metals), hydrogen chloride, and mercury. The primary applicable requirements from NESHAP Subpart AAAAA are summarized below.

Table 1 to Subpart DDDDD of Part 63. Emission Limits and Work Practice Standards

As stated in §63.7500, you must comply with the following applicable emission limits and work practice standards:

For existing large solid fuel fired boilers:

a. Particulate Matter (or Total Selected Metals) ≤ 0.07 lb per MMBtu of heat input; or (0.001 lb per MMBtu of heat input).

b. Hydrogen Chloride ≤ 0.09 lb per MMBtu of heat input.

c. Mercury ≤ 0.000009 lb per MMBtu of heat input.

Table 2 to Subpart DDDDD of Part 63. Operating Limits for Boilers and Process Heaters with Particulate Matter Emission Limits

As stated in §63.7500, you must comply with the applicable operating limits:

1. Wet scrubber control:

   a. Maintain the minimum pressure drop and liquid flow-rate at or above the operating levels established during the performance test according to §63.7530(c) and Table 7 to this subpart that demonstrated compliance with the applicable emission limit for particulate matter.

3. Electrostatic precipitator control

   a. This option is for boilers and process heaters that operate dry control systems. Existing boilers and process heaters must maintain opacity to less than or equal to 20 percent (6-minute average) except for one 6-minute period per hour of not more than 27 percent.

b. This option is only for boilers and process heaters that operate additional wet control systems. Maintain the minimum voltage and secondary current or total power input of the electrostatic precipitator at or above the operating limits established during the performance test according to §63.7530(c) and Table 7 to this subpart that demonstrated compliance with the applicable emission limit for particulate matter.

Table 4 to Subpart DDDDD of Part 63. Operating Limits for Boilers and Process Heaters with Hydrogen Chloride Limits

As stated in §63.7500, you must comply with the following applicable operating limits:

1. Wet scrubber control: Maintain the minimum scrubber effluent pH, pressure drop, and liquid flow-rate at or above the operating levels established during the performance test according to §63.7530(c) and Table 7 to this subpart that demonstrated compliance with the applicable emission limit for hydrogen chloride.

The applicant must also comply with the following applicable requirements in the associated NEHSAP tables based on the control devices and applicable emission standards and operating limits indicated above.

Table 5 Subpart DDDDD of Part 63. Performance Testing Requirements (§63.7520)

Table 6 Subpart DDDDD of Part 63. Fuel Analysis Requirements (§63.7521)

Table 7 to Subpart DDDDD of Part 63. Establishing Operating Limits (§63.7520)

Table 8 to Subpart DDDDD of Part 63. Demonstrating Continuous Compliance (§63.7540)

(Requires a Continuous Opacity Monitoring System.)

Table 9 to Subpart DDDDD of Part 63. Reporting Requirements (§63.7550) .

Rule 62-296.405, F.A.C. - Fossil Fuel Fired Steam Generators with a Maximum Heat Input Rate of 250 MMBtu/hour

This rule establishes standards for nitrogen oxides, opacity, particulate matter, and sulfur dioxide consistent with the requirements of NSPS Subpart D.

Rule 62-296.410, F.A.C. - Carbonaceous Fuel Burning Equipment

This rule establishes the following standards for opacity and particulate matter.

Opacity ≤ 30% except for one 2-minute period per hour of not more than 40% as determined by DEP Method 9

PM ≤ 0.20 lb/MMBtu of heat input of carbonaceous fuel plus 0.1 lb/MMBtu of heat input from fossil fuel as determined by EPA Method 5

Rule 62-212, F.A.C. – Preconstruction Review

In addition to the applicable provisions identified above, the draft permit will include the following preconstruction review requirements.

- Existing Power Boilers 1 – 3 shall cease operation and be permanently shutdown prior to the commencement of commercial operation of new Power Boiler No. 6.
- The permittee shall install, calibrate, operate, and maintain continuous emissions monitoring systems for CO, NOx, SO_2, opacity, flow, and oxygen content.
- CO emissions shall not exceed 394.0 tons during any consecutive 12 months based on CEMS data. All data (including data collected during startup, shutdown, and malfunction), shall be included in the compliance demonstration for this limit. The CO standard also serves as a surrogate for minimizing VOC emissions. {Note: Avoids PSD review pursuant to Rule 62-212.400(2)(g), F.A.C.}
- NOx emissions shall not exceed 380.0 tons during any consecutive 12 months based on CEMS data. All data (including data collected during startup, shutdown, and malfunction), shall be included in the compliance demonstration for this limit. {Note: Avoids PSD review pursuant to Rule 62-212.400(2)(g), F.A.C.}
- SO_2 emissions shall not exceed 210.0 tons during any consecutive 12 months based on CEMS data. All data

(including data collected during startup, shutdown, and malfunction), shall be included in the compliance demonstration for this limit. {Note: Avoids PSD review pursuant to Rule 62-212.400(2)(g), F.A.C.}

- As determined by EPA Method 25A stack test, VOC emissions shall not exceed 0.002 lb/MMBtu measured as carbon. [Rule 62-4.070(3), F.A.C.]
- The maximum continuous steam production rate (24-hour average) shall not exceed 310,000 pounds per hour (525 MMBtu per hour of heat input). Initial and annual compliance testing shall be conducted within 90% of this rate. If initial tests indicate that the unit cannot achieve the specified maximum steam production rate, the air construction permit shall be revised to reflect the actual installed capacity of the unit.
- The maximum annual steam production rate shall not exceed 265,000 pounds per hour (450 MMBtu per hour of heat input) based on a 12-month rolling average basis.
- After completing construction, the permittee shall conduct a test on the new boiler to determine the actual thermal efficiency of the installed boiler.
- Maintain and submit actual annual emissions for 5 years following completion of each project phase. Emissions related to demand growth that could have been accommodated prior to the project must be shown and discussed. This requirement shall be fulfilled by submittal of a report in conjunction with the required Annual Operating Report.

6. DISCUSSION OF NESHAP SUBPART S

Pursuant to § 63.440(d), existing sources must be in compliance with Subpart S no later than April 16, 2001 except as provided in paragraphs (d)(1) through (d)(3). Paragraph (d)(2) applies to the existing dissolving grade bleaching system as follows, "Each dissolving-grade bleaching system at either kraft or sulfite pulping mills shall achieve compliance with the bleach plant provisions of §63.445 of this subpart *as expeditiously as practicable*, but in no event later than 3 years after the promulgation of the revised effluent limitation guidelines and standards under 40 CFR 430.14 through 430.17 and 40 CFR 430.44 through 430.47." In the August of 2005 Federal Register, EPA stated that they would not be promulgating revised effluent limitation guidelines and standards due to the limited number of plants. Instead, EPA will provide technical assistance for each project to implement appropriate waster discharge standards. Therefore, the Department will require compliance with the corresponding air emissions standards within three years of the effective date of this air construction permit to accommodate the aspect of "as expeditiously as practicable" while providing adequate notice to the permittee.

7. PRELIMINARY DETERMINATION

The Department makes a preliminary determination that the proposed project will comply with all applicable state and federal air pollution regulations as conditioned by the draft permit. This determination is based on a technical review of the complete application, reasonable assurances provided by the applicant, and the conditions specified in the draft permit. No air quality modeling analysis is required because the project does not result in a significant increase in emissions. Bruce Mitchell is the project engineer responsible for reviewing the application and drafting the permit. Jeff Koerner is the supervising Professional Engineer. Additional details of this analysis may be obtained by contacting the project engineer at the Department's Bureau of Air Regulation at Mail Station #5505, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400.

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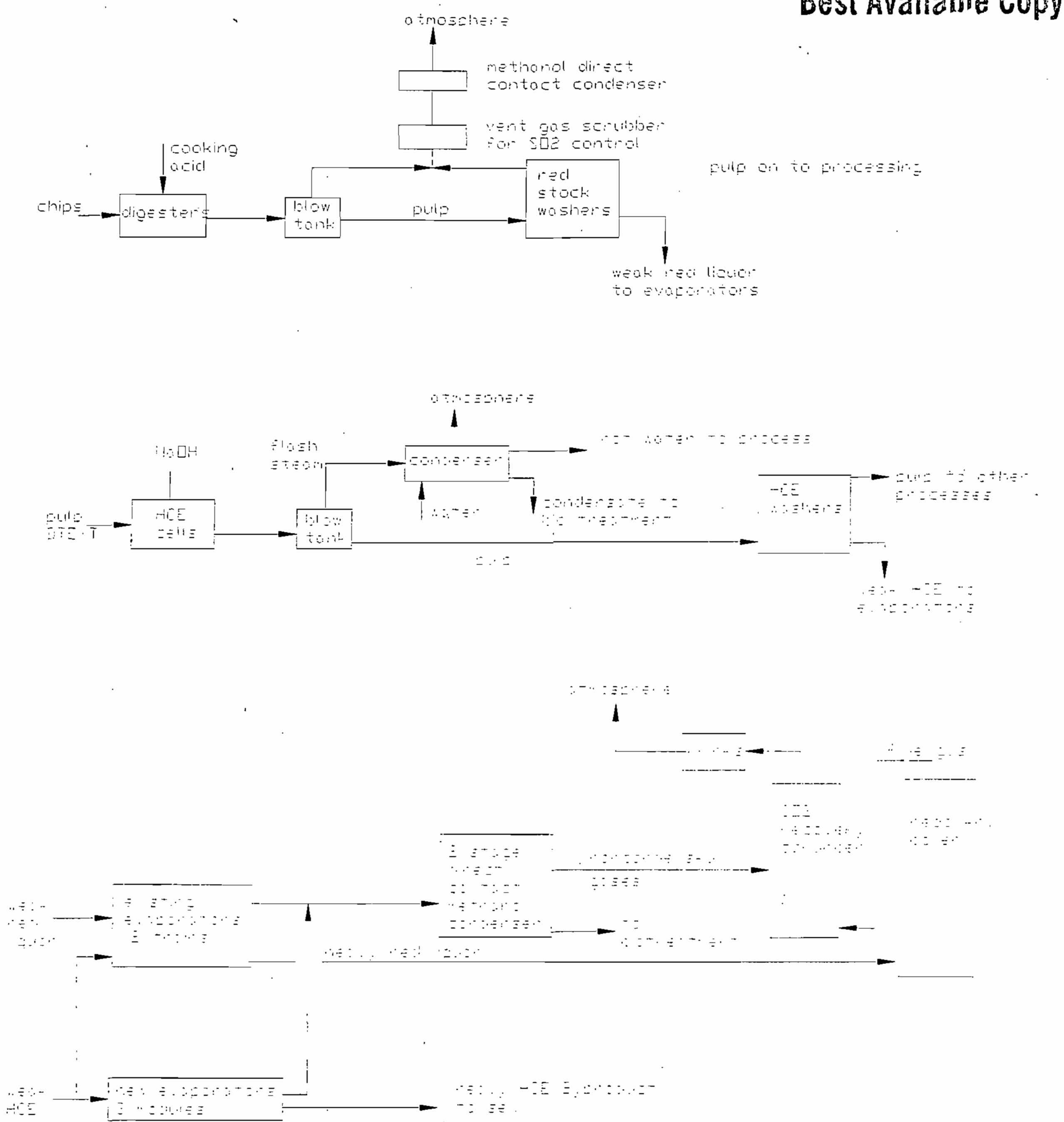

In the Matter of an
Application for Permit by:

Rayonier Performance Fibers LLC
The Foot of Gum Street
Fernandina Beach, Florida 32035-1309
_______________________________________/

Draft Air Construction Permit No.: 0890004-018-AC
Nassau County

INTENT TO ISSUE AN AIR CONSTRUCTION PERMIT

The Department of Environmental Protection (permitting authority) gives notice of its intent to issue An Air Construction Permit (copy of the Draft Air Construction Permit attached) for the facility's modifications detailed in the application specified above, for the reasons stated below.

The permittee, Rayonier Performance Fibers LLC, submitted a request on November 18, 2005, for an Air Construction (AC) Permit for facility modifications located at The Foot of Gum Street, Fernandina Beach, Nassau County.

The subject of the Air Construction Permit is to initially increase the facility's production from 153,205 to 162,000 air dried metric ton (ADMT) per consecutive 12-months, rolling total. After successful installation of a new blow heat recovery system to control VOC (volatile organic compounds) emissions from all HCE cells, production may increase to 175,000 ADMT per consecutive 12-months, rolling total. In order to achieve the increases in production, the permittee will also be authorized to perform the following construction and work: add a new HCE (hot caustic extract) washer press roll; begin first improvements to pulp machine (drying and head-box); add a new HCE evaporator train; install a new HCE blow heat recovery system to control all HCE cells; add a new HCE cell; install a new HCE washer; begin second improvements to pulp machine (drying and speed increase); and, install a new post-HCE washer. The new #6 PB is actually an existing used PB (obtained from another mill and built in 1983) and is being altered from a pulverized coal fired PB to a fluidized-bed wood fired PB; and, the emissions unit will replace three existing fuel-oil fired PBs, Nos. 1, 2 and 3.

The permitting authority has permitting jurisdiction under the provisions of Chapter 403, Florida Statutes (F.S.), and Chapters 62-4, 62-210 and 62-212, F.A.C. This modification is not exempt from permitting procedures. The permitting authority has determined that an Air Construction Permit is required for the proposed modification.

The permitting authority intends to issue the Air Construction Permit based on the belief that reasonable assurances have been provided to indicate that operation of the source will not adversely impact air quality, and the source will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-256, 62-257, 62-281, 62-296, and 62-297, F.A.C.

Pursuant to Sections 403.815 and 403.087, F.S., and Rules 62-110.106 and 62-210.350(3), F.A.C., you (the applicant) are required to publish at your own expense the enclosed "PUBLIC NOTICE OF INTENT TO ISSUE AN AIR CONSTRUCTION PERMIT." The notice shall be published one time only as soon as possible in the legal advertisement section of a newspaper of general circulation in the area affected. For the purpose of these rules, "publication in a newspaper of general circulation in the area affected" means publication in a newspaper meeting the requirements of Sections 50.011 and 50.031, F.S., in the county where the activity is to take place. If you are uncertain that a newspaper meets these requirements, please contact the permitting authority at the address or telephone number listed below. The applicant shall provide proof of publication to the Department's Bureau of Air Regulation, 2600 Blair Stone Road, Mail Station #5505, Tallahassee, Florida 32399-2400 (Telephone: 850/488-1344; Fax: 850/922-6979), within 7 (seven) days of publication. Failure to publish the notice and provide proof of publication within the allotted time may result in the denial of the permit pursuant to Rule 62-110.106, F.A.C.

The permitting authority will issue the Final Air Construction Permit, in accordance with the conditions of the attached Draft Air Construction Permit unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The permitting authority will accept written comments concerning the proposed Air Construction Permit issuance action for a period of 14 (fourteen) days from the date of publication of the "PUBLIC NOTICE OF INTENT TO ISSUE AN AIR CONSTRUCTION PERMIT." Written comments should be provided to the permitting authority office. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in this Draft Air Construction Permit, the permitting authority shall issue a Revised Draft Air Construction Permit and require, if applicable, another Public Notice.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative hearing in accordance with Sections 120.569 and 120.57, F.S. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department of Environmental Protection, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000 (Telephone: 850/245-2241; Fax: 850/245-2303). Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under Section 120.60(3), F.S., must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the permitting authority for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above, at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57, F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205, F.A.C.

A petition that disputes the material facts on which the permitting authority's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner; the name, address and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when each petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, as well as the rules and statutes which entitle the petitioner to relief; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and, (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the permitting authority's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the permitting authority's final action may be different from the position taken by it in this notice of intent. Persons whose substantial interests will be affected by any such final decision of the permitting authority on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

Mediation will not be available in this proceeding.

Persons subject to regulation pursuant to any federally delegated or approved air program should be aware that Florida is specifically not authorized to issue variances or waivers from any requirements of any such federally delegated or approved program. The requirements of the program remain fully enforceable by the Administrator of the United States Environmental Protection Agency and by any person under the Clean Air Act unless and until the Administrator separately approves any variance or waiver in accordance with the procedures of the federal program.

Executed in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Trina L. Vielhauer
Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this INTENT TO ISSUE AN AIR CONSTRUCTION PERMIT (including the PUBLIC NOTICE and Draft Air Construction Permit) and all copies were sent by certified mail before the close of business on 1/26/06 to the person(s) listed:

Mr. F. J. Perrett, Environmental Manager, Rayonier Performance Fibers LLC, Fernandina Beach Mill, The Foot of Gum Street, P.O. Box 2002, Fernandina Beach, Florida 32035-1309

In addition, the undersigned duly designated deputy agency clerk hereby certifies that copies of this INTENT TO ISSUE AN AIR CONSTRUCTION PERMIT (including the PUBLIC NOTICE and Draft Air Construction Permit) were sent by U.S. mail or electronically (Received Receipt requested) on the same date to the person(s) listed:

Mr. Chris Kirts, NED
Mr. David Buff, P.E., GAI
Mr. David Tudor, Application Contact, Rayonier Performance Fibers LLC

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on This date, pursuant to Section 120.52(7), Florida Statutes, with the designated agency Clerk, receipt of which is hereby acknowledged.

Mary L. Harvey 1/26/06
(Clerk) (Date)

PUBLIC NOTICE OF INTENT TO ISSUE AN AIR CONSTRUCTION PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

Draft Air Construction Permit No.: 0890004-018-AC

Rayonier Performance Fibers LLC
Nassau County

The Department of Environmental Protection (permitting authority) gives notice of its intent to issue an Air Construction Permit for the facility modifications requested for Rayonier Performance Fibers LLC's existing sulfite mill, located at The Foot of Gum Street, Nassau County. The applicant's name and address are: Mr. F. J. Perrett, Environmental Manager, Rayonier Performance Fibers LLC, Fernandina Beach Mill, The Foot of Gum Street, P.O. Box 2002, Fernandina Beach, Florida 32035-1309.

The subject of the Air Construction Permit is to initially increase the facility's production from 153,205 to 162,000 air dried metric ton (ADMT) per consecutive 12-months, rolling total. After successful installation of a new blow heat recovery system to control VOC (volatile organic compounds) emissions from all HCE (hot caustic extract) cells, production may increase to 175,000 ADMT per consecutive 12-months, rolling total. In order to achieve the increases in production, the permittee will also be authorized to perform the following construction and work: add a new HCE washer press roll; begin first improvements to pulp machine (drying and head-box); add a new HCE evaporator train; install a new HCE blow heat recovery system to control all HCE cells; add a new HCE cell; install a new HCE washer; begin second improvements to pulp machine (drying and speed increase); and, install a new post-HCE washer. The new #6 PB is actually an existing used PB (obtained from another mill and built in 1983) and is being altered from a pulverized coal fired PB to a fluidized-bed wood fired PB; and, the emissions unit will replace three existing fuel-oil fired PBs, Nos. 1, 2 and 3.

Based on the application and conditions of the draft permit, the project is not subject to preconstruction review for the Prevention of Significant Deterioration (PSD), Rule 62-212.400, F.A.C. The application is structured such that potential emissions from the "new" boiler net out of PSD preconstruction review due to the shutdown of the old power boilers. The combined projects net out of PSD preconstruction review based on the planned installation of additional pollution controls, requested emissions caps, and the applicant's projected actual emissions.

The permitting authority will issue the Final Air Construction Permit in accordance with the conditions of the Draft Air Construction Permit unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The permitting authority will accept written comments concerning the proposed Draft Air Construction Permit issuance action for a period of 14 (fourteen) days from the date of publication of this Notice. Written comments should be provided to the Department's Bureau of Air Regulation, 2600 Blair Stone Road, Mail Station #5505, Tallahassee, Florida 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in this Draft Air Construction Permit, the permitting authority shall issue a Revised Draft Air Construction Permit and require, if applicable, another Public Notice.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative hearing in accordance with Sections 120.569 and 120.57 of the Florida Statutes (F.S.). The petition must contain the information set forth below and must be filed (received) in Office of General Counsel of the Department of Environmental Protection, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000 (Telephone: 850/245-2241; Fax: 850/245-

2303). Petitions filed by any persons other than those entitled to written notice under Section 120.60(3), F.S., must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of the notice of intent, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the permitting authority for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above, at the time of filing. The failure of any person to file a petition within the applicable time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57, F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205, F.A.C.

A petition that disputes the material facts on which the permitting authority's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner; the name, address and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when each petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, as well as the rules and statutes which entitle the petitioner to relief; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and, (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the permitting authority's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the permitting authority's final action may be different from the position taken by it in this notice of intent. Persons whose substantial interests will be affected by any such final decision of the permitting authority on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

Mediation is not available for this proceeding.

A complete project file is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

<u>Permitting Authority:</u>
Department of Environmental Protection
Bureau of Air Regulation
111 South Magnolia Drive, Suite 4
Tallahassee, Florida 32301
Telephone: 850/488-0114
Fax: 850/922-6979

<u>Affected District:</u>
Department of Environmental Protection
Northeast District
7825 Baymeadows Way, Suite 200-B
Jacksonville, Florida 32202
Telephone: 904/807-3300
Fax: 904/488-4363

The complete project file includes the Technical Evaluation and Preliminary Determination and associated Draft Air Construction Permit, the application(s), and the information submitted by the facility's representative, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact Jeffery F. Koerner, P.E., at the above address, or call 850/921-9536, for additional information.

Department of Environmental Protection

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

Jeb Bush
Governor

Colleen M. Castille
Secretary

PERMITTEE:
Rayonier Performance Fibers, LLC
The Foot of Gum Street
Fernandina Beach, Florida 32035-1309

I.D. Number:	0890004
Permit Project No.:	0890004-018-AC
Date of Issue:	Month Day, 2006
Expiration Date:	March 1, 2009
County:	Nassau
Project:	Facility Modification

This permit is issued to allow an increase in the permitted throughput capacity for the facility's operations, the construction/installation of a new #6 Power Boiler (PB), which replaces the three existing ones, and three evaporator bodies to thicken hot caustic extract (HCE), and to recognize the production of the No. 6 Batch Digester. The increase in production will occur in two stages and depends on the installation of some additional equipment. These changes will occur at the existing Rayonier Performance Fibers LLC's Fernandina Beach Dissolving Sulfite Pulp Mill located at The Foot of Gum Street, Fernandina Beach, Nassau County, Florida. UTM Coordinates: Zone 17; 454.7 km East; and, 3392.2 km North; Latitude: 30° 39' 44" North; and, Longitude: 81° 29' 03" West.

First, the initial increase in the facility's production will be from 153,205 to 162,000 air dried metric ton (ADMT) per consecutive 12-months, rolling total. After successful installation of a new blow heat recovery system to control VOC (volatile organic compounds) emissions from all HCE cells, production may increase to 175,000 ADMT per consecutive 12-months, rolling total. In order to achieve the increases in production, the permittee will also be authorized to perform the following construction and work: add a new HCE washer press roll; begin first improvements to pulp machine (drying and head-box); add a new HCE evaporator train; install a new HCE blow heat recovery system to control all HCE cells; add a new HCE cell; install a new HCE washer; begin second improvements to pulp machine (drying and speed increase); and, install a new post-HCE washer. The new #6 PB is actually an existing used PB (obtained from another mill and built in 1983) and is being altered from a pulverized coal fired PB to a fluidized-bed wood fired PB; and, the emissions unit will replace three existing fuel-oil fired PBs, Nos. 1, 2 and 3.

STATEMENT OF BASIS: This air construction permit is issued under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawing(s), plans, and other documents, attached hereto or on file with the permitting authority, in accordance with the terms and conditions of this permit.

Referenced attachments made a part of this permit:
Title V Air Operation Permit: 0890004-011-AV
Appendix SS-1, Stack Sampling Facilities
TABLE 297.310-1, CALIBRATION SCHEDULE version dated 10/07/96
Attachment 40 CFR 60, Subpart A
FIGURE 1 - SUMMARY REPORT - GASEOUS AND OPACITY EXCESS EMISSIONS AND MONITORING SYSTEMS PERFORMANCE REPORT (40 CFR 60, July 1996)
Appendix A to 40 CFR 63, Subpart DDDDD
Appendix B to 40 CFR 63, Subpart DDDDD
Tables to 40 CFR 63, Subpart DDDDD

Michael G. Cooke, Director
Division of Air Resource Management

MGC/tlv/bm

PERMITTEE:

Rayonier Performance Fibers, LLC
Foot of Gum Street
Fernandina Beach, Florida 32035-1339

Facility I.D. Number: 0890004
Permit/Project Number: 0890004-018-AC

GENERAL CONDITIONS:

1. The terms, conditions, requirements, limitations, and restrictions set forth in this permit are "Permit Conditions" and are binding and enforceable pursuant to Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of the conditions.

2. This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings, exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.

3. As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey any vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit is not a waiver of or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.

4. This permit conveys no title to land or water, does not constitute State recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title.

5. This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permitted to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department.

6. The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed and used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules.

7. The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at a reasonable time, access to the premises, where the permitted activity is located or conducted to:

a. Have access to and copy any record that must be kept under the conditions of the permit;

b. Inspect the facility, equipment, practices, or operations regulated or required under this permit; and

c. Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

Reasonable time may depend on the nature of the concern being investigated.

PERMITTEE:

Rayonier Performance Fibers, LLC
Foot of Gum Street
Fernandina Beach, Florida 32035-1339

Facility I.D. Number: 0890004
Permit/Project Number: 0890004-018-AC

GENERAL CONDITIONS:

8. If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately provide the Department with the following information:

   a. a description of and cause of non-compliance; and

   b. the period of non-compliance, including dates and times; or, if not corrected, the anticipated time the non-compliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the non-compliance.

The permittee shall be responsible for any and all damages, which may result and may be subject to enforcement action by the Department for penalties or for revocation of this permit.

9. In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except where such use is prescribed by Sections 403.73 and 403.111, Florida Statutes. Such evidence shall only be used to the extent it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

10. The permittee agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.

11. This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 62-4.120 and 62-730.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.

12. This permit or a copy thereof shall be kept at the work site of the permitted activity.

13. This permit also constitutes:

( ) Determination of Best Available Control Technology (BACT)
( ) Determination of Prevention of Significant Deterioration (PSD)
(X) Compliance with New Source Performance Standards (NSPS)
(X) Compliance with National Emission Standards for Hazardous Air Pollutants/ Maximum Available Control Technology (MACT)

PERMITTEE:

Rayonier Performance Fibers, LLC
Foot of Gum Street
Fernandina Beach, Florida 32035-1339

Facility I.D. Number: 0890004
Permit/Project Number: 0890004-018-AC

GENERAL CONDITIONS:

14. The permittee shall comply with the following:

   a. Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.

   b. The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports required by this permit, and records of all data used to complete the application for this permit. These materials shall be retained at least three years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.

   c. Records of monitoring information shall include:

      - the date, exact place, and time of sampling or measurements;
      - the person responsible for performing the sampling or measurement;
      - the dates analyses were performed;
      - the person responsible for performing the analyses;
      - the analytical techniques or methods used; and
      - the results of such analyses.

15. When requested by the Department, the permittee shall within a reasonable time furnish any information required by law, which is needed to determine compliance with the permit. If the permittee becomes aware that relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.

SPECIFIC CONDITIONS:

A. No. 6 Power Boiler.

E.U. ID No.	**Brief Description**
022	Bubbling Fluidized Bed No. 6 Power Boiler with a Settling Chamber followed by an ESP for PM emissions control and a Wet Alkali Scrubber for SO_2 emissions control

Emissions Unit 022 identifies the No. 6 Power Boiler, which is a converted existing power boiler. It will be firing mostly biomass (green bark, chips, knots and fines), tires, No. 6 fuel oil (max. sulfur content of 2.5%, by weight) and small amounts of facility-generated on-spec used oil (to be blended with the No. 6 fuel oil). The boiler was originally constructed in 1983 as a traveling grate coal-fired boiler.

The converted boiler will include staged combustion and flue gas recirculation (FGR) to reduce NOx emissions. Due to the planned conversion, there is some uncertainty associated with the emissions characteristics. A selective non-catalytic reduction (SNCR) system may be installed to control NOx emissions. This would generally consist of an ammonia tank, pumps, piping, compressed air delivery, injectors, and a control system.

Particulate matter emissions will be controlled with a large setting chamber followed by an electrostatic precipitator (ESP). Large ash particles settle out in the chamber and are removed from the bottom hopper by a screw conveyor system. The design includes a four-field ESP with collector plates and rigid electrodes. Each field will have a dedicated transformer/rectifier (T/R) set and ash hopper. Ash will be removed by a screw conveyor system.

Acid gases will be controlled by a wet alkaline scrubber located after the ESP and induced draft fan. The wet scrubber will spray approximately 4000 gpm of re-circulated alkaline scrubber water over a series of chevrons and louver-type packings to reduce acid gas emissions. The design pressure drop across the system will be approximately 2 inches of water column. Emissions exhaust at a volumetric flow rate of 183,421 acfm and a temperature of 150° F through the single wet scrubber stack that will be approximately 10 feet in diameter and 190 feet above ground level.

{Permitting note(s): This emissions unit is regulated under: 40 CFR 60, Subpart D; and, 40 CFR 63, Subpart DDDDD (by 09/13/07), adopted and incorporated by reference in Rule 62-204.800, F.A.C.}

The following specific conditions apply to the emissions unit listed above:

General

A.0. General.
a. Power Boilers Nos. 1, 2 and 3 shall be permanently shutdown once Power Boiler No. 6 becomes commercially operational and has been compliance tested.
[Rules 62-4.070(3) and 62-212.400(5), F.A.C.]

b. By September 13, 2007, Power Boiler No. 6 shall be in compliance with the requirements of 40 CFR 63, Subparts A and DDDDD (including Appendices A and B), which are a part of the Title V Air Operation Permit, No. 0890004-011-AV, and incorporated by reference.

[Rules 62-4.070(3) and 62-204.800, F.A.C.; and, 40 CFR 63.7495(b)]

SPECIFIC CONDITIONS:

c. References/Acronyms.
   1. SIP: Florida's State Implementation Plan.
   2. NSPS: New Source Performance Standards.
   3. NESHAP: National Emission Standards for Hazardous Air Pollutants.
   4. AC: Air Construction Permit.
   5. PSD NSR: Prevention of Significant Deterioration New Source Review.
   6. CEMS: continuous emissions monitoring system.
   7. COMS: continuous opacity monitoring system.

d. Unless otherwise stated, the "Administrator" is the Department's "Secretary" or its designee.

e. Control Equipment.
   1. To control particulate matter, the permittee shall install a settling chamber (or equivalent) followed by a 4-field electrostatic precipitator designed to achieve at least the emissions standards specified in this permit.
   2. To control acid gases, the permittee shall install a wet alkaline scrubber designed to achieve at least the emissions standards specified in this permit.
   3. To control nitrogen oxides, the converted boiler shall be designed with staged combustion and include flue gas recirculation (FGR). In addition, the permittee is authorized to install (as necessary) a selective non-catalytic reduction system (SNCR) with ammonia injection to achieve at least the emissions standards specified in this permit.

[Rule 62-4.070(3), F.A.C.]

Operational Parameters

A.1. Permitted Capacity. The maximum heat input rates are:
   a. The maximum continuous steam production rate, 24-hour average, is 310,000 lbs/hr based on 525 MMBtu/hr heat input. Initial and annual compliance testing shall be conducted within 90% of this permitted steam rate. If the initial compliance tests cannot be performed at this level, the AC will be modified to reflect the actual installed capacity; and,
   b. The maximum annual steam production rate is 265,000 lbs/hr based on 450 MMBtu/hr heat input. This will require recordkeeping on a 12-month rolling average basis.

[Rules 62-4.070(3), 62-204.800 and 62-212.200 (PTE), F.A.C.; and, application received September 12, 2005]

A.2. Methods of Operation. This boiler may be fired with:
   a. Biomass, consisting of green bark, knots, chips and fines.
   b. Tires.
   c. No. 6 fuel oil, with a maximum sulfur content of 2.5%, by weight, during startup, shutdown, or as a temporary alternate fuel during solid fuel feed upsets.
   d. Facility-generated on-specification used oil, with a maximum sulfur content of 2.5%, by weight, and shall be blended with the No. 6 fuel oil prior to firing.

[Application received September 12, 2005; Rule 62-710.210, F.A.C.; and, 40 CFR Part 279]

A.3. Hours of Operation. The hours of operation are not limited, i.e., 8,760 hours/year.

[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.; and, application received September 12, 2005]

PERMITTEE:

Rayonier Performance Fibers, LLC
Foot of Gum Street
Fernandina Beach, Florida 32035-1339

Facility I.D. Number: 0890004
Permit/Project Number: 0890004-018-AC

SPECIFIC CONDITIONS:

Emission Limits and Standards

*{Permitting Note: Unless otherwise specified, the averaging times for these specific conditions **A.4.** and/thru **A.11.** are based on the specified averaging time of the applicable test method.}*

A.4. Particulate Matter (PM).
a. As determined by an EPA Method 5 or 17 compliance test, PM emissions shall not exceed 0.07 lb/MMBtu heat input; nor 36.75 lbs/hr and 138.0 TPY.

[NESHAP; application received September 12, 2005; ESP design; Rule 62-4.070(3), F.A.C.; 40 CFR 63.7500(a)(1): Table 1 to Subpart DDDDD of Part 63 – Emissions Limits and Work Practice Standards: #9.a.; and, 40 CFR 63.7520(b): Table 5 to Subpart DDDDD of Part 63 – Performance Testing Requirements: #1.e.]

b. As determined by an EPA Method 5 or 5B compliance test, no owner or operator shall cause to be discharged into the atmosphere from any affected facility any gases which:
(1) Contain particulate matter in excess of 43 nanograms per joule heat input (0.10 lb per million Btu) derived from fossil fuel or fossil fuel and wood residue; nor 52.5 lbs/hr.

[NSPS; and, 40 CFR 60.42(a)(1)].

c. As determined by an EPA Method 5 compliance test, PM emissions shall not exceed 0.2 lb/MMBtu heat input of carbonaceous fuel plus 0.1 lb/MMBtu heat input of fossil fuel; nor 105 lbs/hr.

[SIP; and, Rule 62-296.410(2)(b)(2. and Chapter 62-297, F.A.C.]

A.5. Sulfur Dioxide (SO_2).
a. As determined by CEMS data, no owner or operator shall cause to be discharged into the atmosphere from any affected facility any gases which contain sulfur dioxide in excess of:
(1) 340 nanograms per joule heat input (0.80 lb per million Btu and 420 lbs/hr) derived from liquid fossil fuel or liquid fossil fuel and wood residue, and measured as any three-hour period (arithmetic average of three contiguous one-hour periods).

[NSPS; 40 CFR 60.43(a)(1); 40 CFR 60.45(g)(2); applicant requested; and, Rule 62-212.400(2)(g), F.A.C.]

b. In order to escape PSD NSR requirements and as determined by CEMS data, SO_2 emissions shall not exceed 210.0 tons per consecutive 12-month rolling total. All valid CEMS data (including startups, shutdowns and malfunctions) shall be used to determine compliance with this limit.

[Rules 62-4.160(2), 62-210.200(PTE), and 62-212.400(2)(g), F.A.C.; application received September 12, 2005; and, supplemental information received November 7, 2005]

A.6. Nitrogen Oxides (NOx).
a. As determined by CEMS data, no owner or operator shall cause to be discharged into the atmosphere from any affected facility any gases which contain nitrogen oxides, expressed as NO_2, in excess of:
(2) 129 nanograms per joule heat input (0.30 lb per million Btu and 101.20 lbs/hr), and measured as any three-hour period (arithmetic average of three contiguous one-hour periods).

[NSPS; 40 CFR 60.44(a)(2); 40 CFR 60.45(g)(3); applicant requested; and, Rule 62-212.400(2)(g), F.A.C.]

SPECIFIC CONDITIONS:

b. When different fossil fuels are burned simultaneously in any combination, the applicable standard (in ng/J) is determined by proration using the following formula:

$$PS_{NOx} = \frac{w(260)+x(86)+y(130)+z(300)}{w+x+y+z}$$

where:
PS_{NOx} = is the prorated standard for nitrogen oxides when burning different fuels simultaneously, in nanograms per joule heat input derived from all fossil fuels fired or from all fossil fuels and wood residue fired;
w = is the percentage of total heat input derived from lignite;
x = is the percentage of total heat input derived from gaseous fossil fuel;
y = is the percentage of total heat input derived from liquid fossil fuel; and,
z = is the percentage of total heat input derived from solid fossil fuel (except lignite).

[NSPS; and, 40 CFR 60.44(b)]

c. In order to escape PSD NSR requirements and as determined by CEMS data, NOx emissions shall not exceed 380.0 tons per consecutive 12-month rolling total. All valid CEMS data (including startups, shutdowns and malfunctions) shall be used to determine compliance with this limit.

[NSPS; applicant requested; 40 CFR 60.45(g); and, Rule 62-212.400(2)(g), F.A.C.]

A.7. Carbon Monoxide (CO). As determined by CEMS data, CO emissions shall not exceed 0.2 lb/MMBtu heat input; nor 105 lbs/hr and 394.2 tons per consecutive 12-month rolling total. All valid CEMS data (including startups, shutdowns and malfunctions) shall be used to determine compliance with this limit.

[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.; and, application and design received September 12, 2005]

A.8. Volatile Organic Compounds (VOC). As determined by an EPA Method 25A compliance test, VOC emissions shall not exceed 0.002 lb/MMBtu heat input; nor 1.05 lbs/hr and 3.94 TPY.

[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.; application received September 12, 2005; and, supplemental information received November 7, 2005]

A.9. Hydrogen Chloride. As determined by an EPA Method 26A compliance test, hydrogen chloride emissions shall not exceed 0.09 lb/MMBtu heat input. In accordance with the NESHAP, 40 CFR 63, Subpart DDDDD requirements, the permittee shall demonstrate compliance with this standard by September 13, 2007, or within 60 days of initial startup, whichever is later.

[NESHAP; 40 CFR 63.7495(b); 40 CFR 63.7500(a)(1): Table 1 to Subpart DDDDD of Part 63 – Emissions Limits and Work Practice Standards: #9.b.; and, 40 CFR 63.7520(b): Table 5 to Subpart DDDDD of Part 63 – Performance Testing Requirements: #3.e.]

SPECIFIC CONDITIONS:

A.10. Mercury. As determined by an EPA Method 29 or 101A compliance test, mercury emissions shall not exceed 0.000009 lb/MMBtu heat input. In accordance with the NESHAP, 40 CFR 63, Subpart DDDDD requirements, the permittee shall demonstrate compliance with this standard by September 13, 2007, or within 60 days of initial startup, whichever is later.

[NESHAP; 40 CFR 63.7495(b); and, 40 CFR 63.7500(a)(1): Table 1 to Subpart DDDDD of Part 63 – Emissions Limits and Work Practice Standards: #9.c.; 40 CFR 63.7520(b): Table 5 to Subpart DDDDD of Part 63 – Performance Testing Requirements: #4.e.; 40 CFR 60, Appendix A; and, 40 CFR 61, Appendix B]

A.11. Visible Emissions.
a. As determined by COMS data, no owner or operator shall cause to be discharged into the atmosphere from any affected facility any gases which:
(2) Exhibit greater than 20 percent opacity (6-minute average) except for one six-minute period per hour of not more than 27 percent opacity.

[NSPS; 40 CFR 60.42(a)(2); and, 40 CFR 60.45(g)(1)]

b. As determined by a DEP Method 9 compliance test, visible emissions shall not exceed 30 percent opacity except that a density of 40 percent opacity is permissible for not more than two minutes in any one hour.

[SIP; and, Rule 62-296.410(2)(b)1. and Chapter 62-297, F.A.C.]

A.12. Fuel Oil Sulfur Content. As determined by a lab analysis, the sulfur content of the as-fired No. 6 fuel oil shall not exceed 2.5 percent, by weight.

[Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

A.13. "On-Specification" Used Oil. The burning of "on-specification" used oil is allowed at this facility in accordance with all other conditions of this permit and the following additional conditions:
a. Only "on-specification" used oil generated by the facility shall be fired in this emissions unit. The "on-specification" used oil shall be blended with the No. 6 fuel oil prior to firing. "On-specification" used oil is defined as that which meets the 40 CFR 279 (Standards for the Management of Used Oil) specifications listed below. Used oil that does not meet all of the following specifications is considered "off-specification" oil and shall not be fired. See Specific Conditions **A.47.** and **A.48.**

CONSTITUENT / PROPERTY *	ALLOWABLE LEVEL
Arsenic	5 ppm maximum
Cadmium	2 ppm maximum
Chromium	10 ppm maximum
Lead	100 ppm maximum
Total Halogens	1000 ppm maximum
Flash Point	100 °F minimum
PCBs	less than 50 ppm

* As determined by approved methods specified in EPA Publication SW-846 (Test Methods for Evaluating Solid Waste, Physical/Chemical Methods).

[40 CFR 279.11]

SPECIFIC CONDITIONS:

b. Upon request, a certification shall be provided that the used oil (prior to blending with the No. 6 fuel oil) complies with the limits listed above, the provisions of 40 CFR 279 and 761, and shall be recorded and retained on file.

c. "On-specification" used oil may be fired as follows:

1. Any time provided the maximum concentration of PCBs is less than 2 ppm. The analysis and recordkeeping apply to each amount prior to blending even if to be blended with 90% virgin oil.
2. Only during normal operating temperature and not during startup and shutdown if the maximum concentration of $2 \leq \text{PCB} \leq 50$ ppm.

[40 CFR 279 and 761; and, Rule 62-4.070(3), F.A.C.]

Excess Emissions

{Permitting Note: The Excess Emissions Rule at Rule 62-210.700, F.A.C., cannot vary any requirement of a NSPS or NESHAP provision.}

A.14. SIP Excess Emissions – Allowed. Excess emissions resulting from startup, shutdown or malfunction shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration.

[Rule 62-210.700(1), F.A.C.]

A.15. SIP Excess Emissions – Prohibited. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown or malfunction shall be prohibited.

[Rule 62-210.700(4), F.A.C.]

A.16. NSPS Excess Emissions. Excess emission and monitoring system performance reports shall be submitted to the Administrator for each six-month period in the calendar year. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period. Each excess emission and MSP report shall include the information required in Sec. 60.7(c). Periods of excess emissions and monitoring systems (MS) downtime that shall be reported are defined as follows:

(1) Opacity. Excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 20 percent opacity, except that one six-minute average per hour of up to 27 percent opacity need not be reported.

(2) Sulfur dioxide. Excess emissions for affected facilities are defined as:

(i) Any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of sulfur dioxide as measured by a continuous monitoring system exceed the applicable standard under 40 CFR 60.43.

(3) Nitrogen oxides. Excess emissions for affected facilities using a continuous monitoring system for measuring nitrogen oxides are defined as any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards under 40 CFR 60.44.

[40 CFR 60.45(g)]

SPECIFIC CONDITIONS:

Monitoring of Operations

A.17. Determination of Process Variables.
(a) Required Equipment. The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.
(b) Accuracy of Equipment. Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.

[Rule 62-297.310(5), F.A.C.]

A.18. Steam Monitoring. The permittee shall continuously monitor the steam production rate to demonstrate compliance with the requirements of this permit.

[Rule 62-4.070(3), F.A.C.]

A.19. Electrostatic Precipitator-Wet Scrubber Control System: PM. By September 13, 2007, the owner or operator must maintain the minimum voltage and secondary current or total power input of the electrostatic precipitator at or above the operating limits established during the performance test according to 40 CFR 63.7530(c) and Table 7, 40 CFR 63, Subpart DDDDD, that demonstrated compliance with the applicable emission limit for particulate matter. See Specific Condition **A.4.c.**

[40 CFR 63.7500(a)(2): Table 2 to Subpart DDDDD of Part 63 – Emissions Limits and Work Practice Standards: #3.b.]

A.20. Mercury. By September 13, 2007, the owner or operator must comply with the following:
a. Electrostatic Precipitator-Wet Scrubber Control System. Maintain the minimum voltage and secondary current or total power input of the electrostatic precipitator at or above the operating limits established during the performance test according to 40 CFR 63.7530(c) and Table 7, 40 CFR 63, Subpart DDDDD, that demonstrated compliance with the applicable emission limits for mercury. See Specific Condition **A.10.**
b. Fuel Analysis. Maintain the fuel type or fuel mixture such that the mercury emission rates calculated according to 40 CFR 63.7530(d)(4) is less than the applicable emission limits for mercury. See Specific Condition **A.10.**

[40 CFR 63.7500(a)(2): Table 3 to Subpart DDDDD of Part 63 – Emissions Limits and Work Practice Standards: #3.b. and #6, respectively]

A.21. Hydrogen Chloride. By September 13, 2007, the owner or operator must comply with the following:
a. Wet Scrubber Control System: Maintain the minimum scrubber effluent pH, pressure drop, and liquid flow-rate at or above the operating levels established during the performance test according to 40 CFR 63.7530(c) and Table 7, 40 CFR 63, Subpart DDDDD, that demonstrated compliance with the applicable emission limit for hydrogen chloride. See Specific Condition **A.9.**
b. Fuel Analysis: Maintain the fuel type or fuel mixture such that the hydrogen chloride emission rate calculated according to 40 CFR 63.7530(d)(3) is less than the applicable emission limit for hydrogen chloride. See Specific Condition **A.9.**

[40 CFR 63.7500(a)(2): Table 4 to Subpart DDDDD of Part 63 – Emissions Limits and Work Practice Standards: #1 and #3, respectively]

SPECIFIC CONDITIONS:

Continuous Monitoring Requirements

A.22. Each owner or operator shall install, calibrate, maintain, and operate continuous monitoring systems for measuring the opacity of emissions, sulfur dioxide emissions, nitrogen oxides emissions, carbon monoxide emissions and oxygen, in accordance with 40 CFR 60.13, 40 CFR 60.45, and 40 CFR 60, Appendices B and F.

[40 CFR 60.13; 40 CFR 60.45(a); 40 CFR 60, Appendices B and F; Rule 62-4.070(3), F.A.C.; and, application project No. 0890004-018-AC]

A.23. The owner or operator shall install, calibrate, maintain, and operate a continuous flow monitoring system in accordance with 40 CFR 60, Performance Specification 6 of Appendix B and Procedure 1 of Appendix F.

[Application project No. 0890004-018-AC; and, 40 CFR 60, Appendices B and F]

A.24. For performance evaluations under 40 CFR 60.13(c) and calibration checks under 40 CFR 60.13(d), the following procedures shall be used:
(1) Methods 6, 7, and 3B, as applicable, shall be used for the performance evaluations of sulfur dioxide and nitrogen oxides continuous monitoring systems. Acceptable alternative methods for Methods 6, 7, and 3B are given in 40 CFR 60.46(d).
(2) Sulfur dioxide or nitric oxide, as applicable, shall be used for preparing calibration gas mixtures under Performance Specification 2 of Appendix B to 40 CFR 60.
(3) For affected facilities burning fossil fuel(s), the span value for a continuous monitoring system measuring the opacity of emissions shall be 80, 90, or 100 percent and for a continuous monitoring system measuring sulfur oxides or nitrogen oxides the span value shall be determined as follows:

[In parts per million]

Fossil fuel	Span value for sulfur dioxide	Span value for nitrogen oxides
Gas.................................	{1}	500
Liquid..............................	1,000	500
Solid...............................	1,500	1000
Combinations.........................	1,000y + 1,500z	500(x+y) + 1,000z

{1}Not applicable.

where:
x = the fraction of total heat input derived from gaseous fossil fuel, and
y = the fraction of total heat input derived from liquid fossil fuel, and
z = the fraction of total heat input derived from solid fossil fuel.

(4) All span values computed under 40 CFR 60.45(c)(3) for burning combinations of fossil fuels shall be rounded to the nearest 500 ppm.
(5) For a fossil fuel-fired steam generator that simultaneously burns fossil fuel and non-fossil fuel, the span value of all continuous monitoring systems shall be subject to the Administrator's approval.

[40 CFR 60.45(c)]

PERMITTEE:

Rayonier Performance Fibers, LLC
Foot of Gum Street
Fernandina Beach, Florida 32035-1339

Facility I.D. Number: 0890004
Permit/Project Number: 0890004-018-AC

SPECIFIC CONDITIONS:

A.25. For any continuous monitoring system installed under 40 CFR 60.45(a), the following conversion procedures shall be used to convert the continuous monitoring data into units of the applicable standards (ng/J, lb/million Btu):
(1) When a continuous monitoring system for measuring oxygen is selected, the measurement of the pollutant concentration and oxygen concentration shall each be on a consistent basis (wet or dry). Alternative procedures approved by the Administrator shall be used when measurements are on a wet basis. When measurements are on a dry basis, the following conversion procedure shall be used:

$E = CF[20.9/(20.9\text{-percent } O_2)]$

where:

E, C, F, and % O_2 are determined under 40 CFR 60.45(f).

[40 CFR 60.45(e)]

A.26. The values used in the equation under 40 CFR 60.45(e)(1) is derived as follows:
(1) E = pollutant emissions, ng/J (lb/million Btu).
(2) C = pollutant concentration, ng/dscm (lb/dscf), determined by multiplying the average concentration (ppm) for each one-hour period by 4.15×10^{4} M ng/dscm per ppm (2.59×10^{-9} M lb/dscf per ppm) where M = pollutant molecular weight, g/g-mole (lb/lb-mole). M = 64.07 for sulfur dioxide and 46.01 for nitrogen oxides.
(3) % O_2, %CO_2 = oxygen or carbon dioxide volume (expressed as percent), determined with equipment specified under 40 CFR 60.45(a).
(4) F, F_c = a factor representing a ratio of the volume of dry flue gases generated to the calorific value of the fuel combusted (F), and a factor representing a ratio of the volume of carbon dioxide generated to the calorific value of the fuel combusted (F_c), respectively. Values of F and F_c are given as follows:

(iii) For liquid fossil fuels including crude, residual, and distillate oils, $F = 2.476 \times 10^{-7}$ dscm/J (9,220 dscf/million Btu) and $F_c = 0.384 \times 10^{-7}$ scm CO_2 /J (1,430 scf CO_2 /million Btu).

(v) For bark $F = 2.589 \times 10^{-7}$ dscm/J (9,640 dscf/million Btu) and $F_c = 0.500 \times 10^{-7}$ scm CO_2 /J (1,840 scf CO_2 / million Btu). For wood residue other than bark $F = 2.492 \times 10^{-7}$ dscm/J (9,280 dscf/million Btu) and Fc $= 0.494 \times 10^{-7}$ scm CO_2 /J (1,860 scf CO_2 / million Btu).

(5) The owner or operator may use the following equation to determine an F factor (dscm/J or dscf/million Btu) on a dry basis (if it is desired to calculate F on a wet basis, consult the Administrator) or F_c factor (scm CO_2 /J, or scf CO_2 /million Btu) on either basis in lieu of the F or F_c factors specified in 40 CFR 60.45(f)(4):

$$F = 10^6 \frac{[227.2 (\text{pct. H}) + 95.5 (\text{pct. C}) + 35.6 (\text{pct. S}) + (\text{pct. N}) - 28.7 (\text{pct. O})]}{\text{GCV}}$$

$$F_c = \frac{2.0 \times 10^{-5} (\text{pct. C})}{\text{GCV (SI units)}}$$

$$F = 10^6 \frac{3.64(\%H) + 1.53(\%C) + 0.57(\%S) + 0.14(\%N) - 0.46(\%O)}{\text{GCV (English units)}}$$

$$F_c = \frac{20.0(\%C)}{\text{GCV (SI units)}}$$

$$Fc = \frac{321 \times 10^3(\%C)}{\text{GCV (English units)}}$$

SPECIFIC CONDITIONS:

(i) H, C, S, N, and O are content by weight of hydrogen, carbon, sulfur, nitrogen, and oxygen (expressed as percent), respectively, as determined on the same basis as GCV by ultimate analysis of the fuel fired, using ASTM method D3178-73 (Reapproved 1979), 89, or D3176-74 or 89 (solid fuels) or computed from results using ASTM method D1137-53 or 75, D1945-64, 76, 91, or 96 or D1946-77 or 90 (Reapproved 1994) (gaseous fuels) as applicable. (These five methods are incorporated by reference-see 40 CFR 60.17.)
(ii) GCV is the gross calorific value (kJ/kg, Btu/lb) of the fuel combusted determined by the ASTM test methods D2015-77 (Reapproved 1978), 96, or D5865-98 for solid fuels and D1826-77 or 94 for gaseous fuels as applicable. (These two methods are incorporated by reference-see 40 CFR 60.17.)
(iii) For affected facilities which fire both fossil fuels and non-fossil fuels, the F or F_c value shall be subject to the Administrator's approval.

(6) For affected facilities firing combinations of fossil fuels or fossil fuels and wood residue, the F or F_c factors determined by paragraphs 40 CFR 60.45(f)(4) or (f)(5) shall be prorated in accordance with the applicable formula as follows:

$$F = \sum_{i=1}^{n} X_i F_i \quad \text{or} \quad F_c = \sum_{i=1}^{n} X_i (F_c)_i$$

where:

X_i = the fraction of total heat input derived from each type of fuel (e.g. natural gas, bituminous coal, wood residue, etc.)
F_i or $(F_c)_i$ = the applicable F or F_c factor for each fuel type determined in accordance with paragraphs (f)(4) and (f)(5) of this section.
n = the number of fuels being burned in combination.

[40 CFR 60.45(f)]

Test Methods and Procedures

A.27. In conducting the performance tests required in 40 CFR 60.8, the owner or operator shall use as reference methods and procedures the test methods in Appendix A of 40 CFR 60 or other methods and procedures as specified in 40 CFR 60.46, except as provided in 40 CFR 60.8(b). Acceptable alternative methods and procedures are given in 40 CFR 60.46(d).

[40 CFR 60.46(a)]

A.28. Boiler Thermal Efficiency. In conjunction with the initial performance tests, the permittee shall determine the installed boiler's thermal efficiency while combusting 100% wood and also 100% fuel oil.

[Rule 62-4.070(3), F.A.C.]

SPECIFIC CONDITIONS:

A.29. The owner or operator shall determine compliance with the particulate matter, SO_2, and NO_x standards in 40 CFR 60.42, 60.43, and 60.44 as follows:
(1) The emission rate (E) of particulate matter, SO_2, or NO_x shall be computed for each run using the following equation:

$E = C\,F_d\,(20.9)/(20.9 - \%\,O_2)$
where:
E = emission rate of pollutant, ng/J (1b/million Btu).
C = concentration of pollutant, ng/dscm (1b/dscf).
$\%\,O_2$ = oxygen concentration, percent dry basis.
F_d = factor as determined from Method 19.

[40 CFR 60.46(b)(1)]

A.30. <u>PM Emissions</u>.
a. For the NSPS limit, EPA Method 5 shall be used to determine the particular matter concentration (C) at affected facilities without wet flue-gas-desulfurization (FGD) systems and EPA Method 5B shall be used to determine the particulate matter concentration (C) after FGD systems. See Specific Condition **A.4.a.**

(i) The sampling time and sample volume for each run shall be at least 60 minutes and 0.85 dscm (30 dscf). The probe and filter holder heating systems in the sampling train shall be set to provide an average gas temperature of 160 ± 14 °C (320 ± 25 °F).

(ii) The emission rate correction factor, integrated or grab sampling and analysis procedure of EPA Method 3B shall be used to determine the O_2 concentration ($\%O_2$). The O_2 sample shall be obtained simultaneously with, and at the same traverse points as, the particulate sample. If the grab sampling procedure is used, the O_2 concentration for the run shall be the arithmetic mean of the sample O_2 sample concentrations at all traverse points.

(iii) If the particulate run has more than 12 traverse points, the O_2 traverse points may be reduced to 12 provided that Method 1 is used to locate the 12 O_2 traverse points.

[40 CFR 60.46(b)(2)]

b. For the SIP limit, the test method for PM shall be EPA Method 5, incorporated and adopted by reference in Chapter 62-297, F.A.C. See Specific Condition **A.4.b.**
c. Test procedures shall meet all applicable requirements of Chapter 62-297, F.A.C.

[Rules 62-296.410(3)(b) & (c), F.A.C.]

d. A compliance test shall be conducted initially and once each federal fiscal year.

[Rule 62-297.310(7)(a)4., F.A.C.]

SPECIFIC CONDITIONS:

A.31. Sulfur Dioxide Emissions.
a. EPA Method 6 shall be used to determine the SO_2 concentration.
(i) The sampling site shall be the same as that selected for the particulate sample. The sampling location in the duct shall be at the centroid of the cross section or at a point no closer to the walls than 1 m (3.28 ft). The sampling time and sample volume for each sample run shall be at least 20 minutes and 0.020 dscm (0.71 dscf). Two samples shall be taken during a 1-hour period, with each sample taken within a 30-minute interval.
(ii) The emission rate correction factor, integrated sampling and analysis procedure of EPA Method 3B shall be used to determine the O_2 concentration (%O_2). The O_2 sample shall be taken simultaneously with, and at the same point as, the SO_2 sample. The SO_2 emission rate shall be computed for each pair of SO_2 and O_2 samples. The SO_2 emission rate (E) for each run shall be the arithmetic mean of the results of the two pairs of samples.

[40 CFR 60.46(b)(4)]

b. A compliance test shall be conducted initially and in accordance with 40 CFR 60.8. Continuous compliance shall be demonstrated by the required emissions monitoring system.

[40 CFR 60.8; and, Rule 62-297.310(7)(a)4., F.A.C.]

A.32. Nitrogen Oxides Emissions.
a. EPA Method 7 shall be used to determine the NO_X concentration.
(i) The sampling site and location shall be the same as for the SO_2 sample. Each run shall consist of four grab samples, with each sample taken at about 15-minute intervals.
(ii) For each NO_X sample, the emission rate correction factor, grab sampling and analysis procedure of EPA Method 3B shall be used to determine the O_2 concentration (%O_2). The sample shall be taken simultaneously with, and at the same point as, the NO_X sample.
(iii) The NO_X emission rate shall be computed for each pair of NO_X and O_2 samples. The NO_X emission rate (E) for each run shall be the arithmetic mean of the results of the four pairs of samples.

[40 CFR 60.46(b)(5)]

b. A compliance test shall be conducted initially and in accordance with 40 CFR 60.8. Continuous compliance shall be demonstrated by the required emissions monitoring system.

[40 CFR 60.8; and, Rule 62-297.310(7)(a)4., F.A.C.]

A.33. CO Emissions. The test method for carbon monoxide emissions shall be EPA Method 10, incorporated in Chapter 62-297, F.A.C. A compliance test shall be conducted initially and in accordance with 40 CFR 60.8. Continuous compliance shall be demonstrated by the required emissions monitoring system.

[40 CFR 60.8; and, Rules 62-297.401 and 62-297.310(7)(a)4., F.A.C.]

A.34. VOC Emissions.
a. The test method for VOC emissions shall be EPA Method 25A, incorporated in Chapter 62-297, F.A.C. A compliance test shall be conducted initially and in accordance with 40 CFR 60.8.; and, once every five years for renewal.

[40 CFR 60.8; and, Rules 62-297.401 and 62-297.310(7)(a)4., F.A.C.]

PERMITTEE:

Rayonier Performance Fibers, LLC
Foot of Gum Street
Fernandina Beach, Florida 32035-1339

Facility I.D. Number: 0890004
Permit/Project Number: 0890004-018-AC

SPECIFIC CONDITIONS:

A.35. Visible Emissions.
a. For the NSPS limit, EPA Method 9 and the procedures in 40 CFR 60.11 shall be used to determine opacity. Compliance shall be demonstrated by COMS. See Specific Condition **A.11.a.**

[40 CFR 60.11; and, 40 CFR 60.46(b)(3)]

b. For the SIP limit, the test method for visible emissions shall be DEP Method, incorporated in Chapter 62-297, F.A.C. See Specific Conditions **A.11.b.** and **A.36.**
c. Test procedures shall meet all applicable requirements of Chapter 62-297, F.A.C.

[Rules 62-296.410(3)(a) & (c), F.A.C.]

d. A compliance test shall be conducted initially and in accordance with 40 CFR 60.8. Continuous compliance shall be demonstrated by COMS.

[40 CFR 60.8; and, Rule 62-297.310(7)(a)4., F.A.C.]

A.36. DEP Method 9. The provisions of EPA Method 9 (40 CFR 60, Appendix A) are adopted by reference with the following exceptions:
1. EPA Method 9, Section 2.4, Recording Observations. Opacity observations shall be made and recorded by a certified observer at sequential fifteen second intervals during the required period of observation.
2. EPA Method 9, Section 2.5, Data Reduction. For a set of observations to be acceptable, the observer shall have made and recorded, or verified the recording of, at least 90 percent of the possible individual observations during the required observation period. For single-valued opacity standards (e.g., 20 percent opacity), the test result shall be the highest valid six-minute average for the set of observations taken. For multiple-valued opacity standards (e.g., 20 percent opacity, except that an opacity of 40 percent is permissible for not more than two minutes per hour) opacity shall be computed as follows:

a. For the basic part of the standard (i.e., 20 percent opacity) the opacity shall be determined as specified above for a single-valued opacity standard.

b. For the short-term average part of the standard, opacity shall be the highest valid short-term average (i.e., two-minute, three-minute average) for the set of observations taken.

In order to be valid, any required average (i.e., a six-minute or two-minute average) shall be based on all of the valid observations in the sequential subset of observations selected, and the selected subset shall contain at least 90 percent of the observations possible for the required averaging time. Each required average shall be calculated by summing the opacity value of each of the valid observations in the appropriate subset, dividing this sum by the number of valid observations in the subset, and rounding the result to the nearest whole number. The number of missing observations in the subset shall be indicated in parenthesis after the subset average value.

[Rule 62-297.401, F.A.C.]

SPECIFIC CONDITIONS:

A.37. Fuel Analyses. For Power Boiler No. 6, the following fuel sampling and analysis protocol shall be used:
a. Determine and record the as-fired fuel sulfur content, percent by weight, for liquid fuels using either ASTM D2622-92, ASTM D4294-90, both ASTM D4057-88 and ASTM D129-91, or the latest edition, by analyzing a representative sample of the blended fuel oil following each fuel delivery.
b. Record hourly fuel totalizer readings with calculated hourly feed rates for each fuel fired, the ratio of fuels fired, the density of each fuel, and the percent sulfur content, by weight, of each fuel.
c. The analyses of the No. 6 fuel oil, as received from the supplier in a bill of lading, shall include the following:
1. Density (ASTM D 1298-80 or the latest edition).
2. Calorific heat value in Btu per pound (ASTM D 240-76 or the latest edition).
3. Sulfur content, by weight (ASTM D2622-92, ASTM D4294-90, both ASTM D4057-88 and ASTM D129-91, or the latest edition).

d. On a quarterly basis, an analyses of the wood fuel shall include the following:
1. Calorific heat value in Btu per pound (ASTM D2015-77, or the latest edition).
2. Moisture content (ASTM D2016-74, 83, or the latest edition).
3. Sulfur content, by weight (Test Methods for Evaluating Solid Waste, Physical/Chemical Methods: EPA Publication SW-846 Third Edition (November 1986), or the latest edition).

[40 CFR 60, Subpart A]

A.38. Required Number of Test Runs. For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured provided, however, that three complete and separate determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the owner or operator, and a valid third run cannot be obtained within the five day period allowed for the test, the Secretary or his or her designee may accept the results of the two complete runs as proof of compliance, provided that the arithmetic mean of the results of the two complete runs is at least 20 percent below the allowable emission limiting standards.

[Rule 62-297.310(1), F.A.C.]

A.39. Operating Rate During Testing.
a. Testing of emissions shall be conducted with each emissions unit operation at permitted capacity, which is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impracticable to test at permitted capacity, an emissions unit may be tested at less than the minimum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test load until a new test is conducted. Once the emissions unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity.

[Rules 62-297.310(2) & (2)(b), F.A.C.]

b. If the new emissions unit is unable to achieve the designed permitted capacity (at least 90%) for the initial tests, then this permit will be revised to reflect the true installed capacity.

[Rule 62-4.070(3), F.A.C.]

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SPECIFIC CONDITIONS:

A.40. Calculation of Emission Rate. The indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the separate test runs unless otherwise specified in a particular test method or applicable rule.

[Rule 62-297.310(3), F.A.C.]

A.41. Applicable Test Procedures.

(a) Required Sampling Time.

1. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes.

2. Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:

c. The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.

(b) Minimum Sample Volume. Unless otherwise specified in the applicable rule, the minimum sample volume per run shall be 25 dry standard cubic feet.

(c) Required Flow Rate Range. For EPA Method 5 particulate sampling, acid mist/sulfur dioxide, and fluoride sampling which uses Greenburg Smith type impingers, the sampling nozzle and sampling time shall be selected such that the average sampling rate will be between 0.5 and 1.0 actual cubic feet per minute, and the required minimum sampling volume will be obtained.

(d) Calibration of Sampling Equipment. Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1 (attached).

(e) Allowed Modification to EPA Method 5. When EPA Method 5 is required, the following modification is allowed: the heated filter may be separated from the impingers by a flexible tube.

[Rule 62-297.310(4), F.A.C.]

A.42. Required Stack Sampling Facilities. When a mass emissions stack test is required, the permittee shall comply with the requirements contained in Appendix SS-1, Stack Sampling Facilities, attached to this permit.

[Rule 62-297.310(6), F.A.C.]

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SPECIFIC CONDITIONS:

A.43. Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.

(a) General Compliance Testing.

2. For excess emission limitations for particulate matter specified in Rule 62-210.700, F.A.C., a compliance test shall be conducted annually while the emissions unit is operating under soot blowing conditions in each federal fiscal year during which soot blowing is part of normal emissions unit operation, except that such test shall not be required in any federal fiscal year in which a fossil fuel steam generator does not burn liquid fuel for more than 400 hours other than during startup.

3. The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision. In renewing an air operation permit pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal:

a. Did not operate; or

b. In the case of a fuel burning emissions unit, burned liquid fuel for a total of no more than 400 hours.

4. During each federal fiscal year (October 1 – September 30), unless otherwise specified by rule, order, or permit, the owner or operator of each emissions unit shall have a formal compliance test conducted for:

a. Visible emissions, if there is an applicable standard;

b. Each of the following pollutants, if there is an applicable standard, and if the emissions unit emits or has the potential to emit: 5 tons per year or more of lead or lead compounds measured as elemental lead; 30 tons per year or more of acrylonitrile; or 100 tons per year or more of any other regulated air pollutant; and

c. Each NESHAP pollutant, if there is an applicable emission standard.

5. An annual compliance test for particulate matter emissions shall not be required for any fuel burning emissions unit that, in a federal fiscal year, does not burn liquid fuel, other than during startup, for a total of more than 400 hours.

9. The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.

(b) Special Compliance Tests. When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it may require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant
emissions from the emissions unit and to provide a report on the results of said tests to the Department.

(c) Waiver of Compliance Test Requirements. If the owner or operator of an emissions unit that is subject to a compliance test requirement demonstrates to the Department, pursuant to the procedure established in Rule 62-297.620, F.A.C., that the compliance of the emissions unit with an applicable weight emission limiting standard can be adequately determined by means other than the designated test procedure, such as specifying a surrogate standard of no visible emissions for particulate matter sources equipped with a bag house or specifying a fuel analysis for sulfur dioxide emissions, the Department shall waive the compliance test requirements for such emissions units and order that the alternate means of determining compliance be used, provided, however, the provisions of Rule 62-297.310(7)(b), F.A.C., shall apply.

[Rule 62-297.310(7), F.A.C.; and, SIP approved]

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SPECIFIC CONDITIONS:

Recordkeeping and Reporting Requirements

A.44. Notification.
a. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department's NED office in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department's NED.

[Rule 62-210.700(6), F.A.C.]

b. If CEMS or COMS data indicates non-compliance, the permittee shall notify the Department's NED office within one working day of such determination.

[Rule 62-4.070(3), F.A.C.]

A.45. Plant Operation - Problems. If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the owner or operator shall notify the Department as soon as possible, but at least within one (1) working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; the steps being taken to correct the problem and prevent future recurrence; and where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit and the regulations.

[Rule 62-4.130, F.A.C.]

A.46. Test Reports.
(a) The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department's NED on the results of each such test.
(b) The required test report shall be filed with the Department's NED as soon as practical but no later than 45 days after the last sampling run of each test is completed.
(c) The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the Department's NED to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information:

1. The type, location, and designation of the emissions unit tested.
2. The facility at which the emissions unit is located.
3. The owner or operator of the emissions unit.
4. The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.
5. The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.
6. The type of air pollution control devices installed on the emissions unit, their general condition, their normal operating parameters (pressure drops, total operating current and GPM scrubber water), and their operating parameters during each test run.
7. A sketch of the duct within 8 stack diameters upstream and 2 stack diameters downstream of the sampling ports, including the distance to any upstream and downstream bends or other flow disturbances.
8. The date, starting time and duration of each sampling run.
9. The test procedures used, including any alternative procedures authorized pursuant to Rule 62-297.620, F.A.C. Where optional procedures are authorized in this chapter, indicate which option was used.
10. The number of points sampled and configuration and location of the sampling plane.
11. For each sampling point for each run, the dry gas meter reading, velocity head, pressure drop across the stack, temperatures, average meter temperatures and sample time per point.

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12. The type, manufacturer and configuration of the sampling equipment used.
13. Data related to the required calibration of the test equipment.
14. Data on the identification, processing and weights of all filters used.
15. Data on the types and amounts of any chemical solutions used.
16. Data on the amount of pollutant collected from each sampling probe, the filters, and the impingers, are reported separately for the compliance test.
17. The names of individuals who furnished the process variable data, conducted the test, analyzed the samples and prepared the report.
18. All measured and calculated data required to be determined by each applicable test procedure for each run.
19. The detailed calculations for one run that relate the collected data to the calculated emission rate.
20. The applicable emission standard, and the resulting maximum allowable emission rate for the emissions unit, plus the test result in the same form and unit of measure.
21. A certification that, to the knowledge of the owner or his authorized agent, all data submitted are true and correct. When a compliance test is conducted for the Department or its agent, the person who conducts the test shall provide the certification with respect to the test procedures used. The owner or his authorized agent shall certify that all data required and provided to the person conducting the test are true and correct to his knowledge.

[Rules 62-213.440 and 62-297.310(8), F.A.C.]

A.47. Monthly records shall be kept of the quantity of "on-specification" used oil fired in these emissions units. The above records shall be maintained in a form suitable for inspection, retained for a minimum of five years, and be made available upon request. See Specific Conditions **A.13.** and **A.48.**

[Rule 62-213.440(1)(b)2.b., F.A.C.; and, 40 CFR 279.61 and 761.20(e)]

A.48. The permittee shall include in the "Annual Operating Report for Air Pollutant Emitting Facility" a summary of the "on-specification" used oil fired in the No. 6 Power Boiler during the calendar year. See Specific Conditions **A.13.** and **A.47.**

[Rule 62-213.440(1)(b)2.b., F.A.C.]

A.49. NSPS Excess Emission and Monitoring System Performance Reports. Excess emission and monitoring system performance reports shall be submitted to the Administrator for each six-month period in the calendar year. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period. Each excess emission and MSP report shall include the information required in Sec. 60.7(c). Periods of excess emissions and monitoring systems (MS) downtime that shall be reported are defined as follows:

(1) Opacity. Excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 20 percent opacity, except that one six-minute average per hour of up to 27 percent opacity need not be reported.

(2) Sulfur dioxide. Excess emissions for affected facilities are defined as:

(i) Any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of sulfur dioxide as measured by a continuous monitoring system exceed the applicable standard established under 40 CFR 60.43. See Specific Condition **A.5.a.(1).**

(3) Nitrogen oxides. Excess emissions for affected facilities using a continuous monitoring system for measuring nitrogen oxides are defined as any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards under 40 CFR 60.44. See Specific Condition **A.6.a.(2).**

[40 CFR 60.45(g)(1), (2) & (3)]

SPECIFIC CONDITIONS:

A.50. Within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of such facility and at such other times as may be required by the Administrator under section 114 of the Act, the owner or operator of such facility shall conduct performance test(s) and furnish the Administrator a written report of the results of such performance test(s).

[40 CFR 60.8(a)]

A.51. Performance tests shall be conducted and data reduced in accordance with the test methods and procedures contained in each applicable subpart unless the Administrator:
(1) Specifies or approves, in specific cases, the use of a reference method with minor changes in methodology;
(2) Approves the use of an equivalent method;
(3) Approves the use of an alternative method the results of which he has determined to be adequate for indicating whether a specific source is in compliance;
(4) Waives the requirement for performance tests because the owner or operator of a source has demonstrated by other means to the Administrator's satisfaction that the affected facility is in compliance with the standard; or
(5) Approves shorter sampling times and smaller sample volumes when necessitated by process variables or other factors. Nothing in 40 CFR 60.8 shall be construed to abrogate the Administrator's authority to require testing under section 114 of the Act.

[40 CFR 60.8(b)(1), (2), (3), (4) & (5)]

A.52. Performance tests shall be conducted under such conditions as the Administrator shall specify to the plant operator based on representative performance of the affected facility. The owner or operator shall make available to the Administrator such records as may be necessary to determine the conditions of the performance tests. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a performance test nor shall emissions in excess of the level of the applicable emission limit during periods of startup, shutdown, and malfunction be considered a violation of the applicable emission limit unless otherwise specified in the applicable standard.

[40 CFR 60.8(c)]

A.53. The owner or operator of an affected facility shall provide the Administrator at least 30 days prior notice of any performance test, except as specified under other subparts, to afford the Administrator the opportunity to have an observer present. If after 30 days notice for an initially scheduled performance test, there is a delay (due to operational problems , etc) in conducting the scheduled performance test, the owner or operator of an affected facility shall notify the administrator (or delegated State or local agency) as soon as possible of any delay in the original test date, either by providing at least 7 days prior notice of the rescheduled date of the performance test, or by arranging a rescheduled date with the Administrator (or delegated State or local agency) by mutual agreement.

[40 CFR 60.8(d)]

SPECIFIC CONDITIONS:

A.54. The owner or operator of an affected facility shall provide, or cause to be provided, performance testing facilities as follows:

(1) Sampling ports adequate for test methods applicable to such facility. This includes
(i) constructing the air pollution control system such that volumetric flow rates and pollutant emission rates can be accurately determined by applicable test methods and procedures and
(ii) providing a stack or duct free of cyclonic flow during performance tests, as demonstrated by applicable test methods and procedures.
(2) Safe sampling platform(s).
(3) Safe access to sampling platform(s).
(4) Utilities for sampling and testing equipment.

[40 CFR 60.8(e)(1), (2), (3) & (4)]

A.55. Unless otherwise specified in the applicable subpart, each performance test shall consist of three separate runs using the applicable test method. Each run shall be conducted for the time and under the conditions specified in the applicable standard. For the purpose of determining compliance with an applicable standard, the arithmetic means of results of the three runs shall apply. In the event that a sample is accidentally lost or conditions occur in which one of the three runs must be discontinued because of forced shutdown, failure of an irreplaceable portion of the sample train, extreme meteorological conditions, or other circumstances, beyond the owner or operator's control, compliance may, upon the Administrator's approval, be determined using the arithmetic mean of the results of the two other runs.

[40 CFR 60.8(f)]

B. <u>No. 6 Batch Digester</u>.

B.1. The new No. 6 batch digester is in operation and included in with the "batch digesters" under Emissions Unit 005, Vent Gas Scrubber and Direct Contact Condenser", and is subject to the terms and conditions established for this emissions unit in Title V permit, No. 0890004-011-AV, specifically in Subsection G., which is incorporated by reference.

{Emission Unit 005 includes the vent gas scrubber (wet scrubber), which controls emissions from numerous vents from the cooking acid plant, the red stock washers, the unwashed stock tank, the spent sulfite liquor storage tanks, the spent sulfite liquor washer area, the digesters, and the blow pits. The scrubber is a packed bed containing 10 feet of packing consisting of two packed sections. The lower section is designed for sulfur dioxide emissions control via gas absorption using alkaline scrubbing media (soda ash, sodium hydroxide, etc.). The spent scrubber media is bled first to other closed sources to make maximum us of the alkali to remove sulfur dioxide, and then to sewer via closed piping to number 1 Pump Station. The sulfur dioxide concentration in the stack is continuously measured with a CMS.

The upper packed section of the vent gas scrubber is designed to condense methanol from the gas stream by direct contact with fresh well water, i.e. the Direct Contact Condenser. This is a once through process. The condensed methanol held in the water is sent to the biological effluent treatment system for treatment in order to comply with the requirements of 40 CFR 63, Subpart S.}

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SPECIFIC CONDITIONS:

C. Multiple Effect Evaporators (3 bodies).

C.1. The permittee is authorized to install three (3) new Multiple Effect Evaporators (MEEs) bodies, which are refurbished existing units. They will form a new train to be used to increase the solids concentration of weak HCE, a byproduct stream from the manufacturing process that can be used at Kraft mills as a sodium source. All of the MEEs will vent through a common condenser used to collect methanol and then vented to the atmosphere via the sulfur dioxide recovery scrubber for the recovery boiler. The new bodies will be lumped in with the two sets of MEEs and will now be described as "three" sets of MEEs under Emissions Unit 021, and subject to the terms and conditions established for this emissions unit in Title V permit, No. 0890004-011-AV, specifically in Subsection G., which is incorporated by reference.

{Emissions Unit 021 includes the Evaporator Vents Methanol Condenser System. The steam that is used to eject the vent gases from the two sets of multiple effect evaporators along with the evaporator vent gases themselves, are piped to a pre-condenser which condenses the steam followed by the main condenser which condenses the methanol. The water used to condense the steam and methanol is reclaimed from the biological effluent treatment system after the methanol has been digested.

The condensate from the pre-condenser and the main condenser are sewered to the biological effluent treatment system via the Number 3 Pump Station for compliance with the 40 CFR 63, Subpart S requirements.

The non-condensable gases from the main condenser are sent to the multi-stage wet scrubber/Brinks Demister at the Recovery boiler (Emissions Unit No. 006).}

D. Facility.

D.1. Capacity.
a. Except as provided below, the facility's production shall not exceed 162,000 air dried metric tons (ADMT) per consecutive 12-months, rolling total.
b. Upon successful installation and submittal of the engineering report of the HCE blow heat recovery system to control VOC emissions from all of the HCE cells, the facility's production shall not exceed 175,000 ADMT per consecutive 12-months, rolling total.

[Rules 62-4.070(3), 210.200(PTE) and 62-212.400(5), F.A.C.]

D.2. The application indicates the following preliminary schedule for commencing construction:

Date	Activity
February 2006	Add a new HCE washer press roll
February 2007	Begin first improvements to pulp machine (drying and head-box)
	Add a new HCE evaporator train
February 2008	Install a new HCE blow heat recovery system to control all HCE cells
	Add a new HCE cell
	Install a new HCE washer
	Begin second improvements to pulp machine (drying and speed increase)
	Install a new post-HCE washer

* It is noted that some of the later changes are contingent on the success of the earlier stages.

SPECIFIC CONDITIONS:

D.3. The permittee is authorized to perform the following construction and work:

a. add a new HCE washer press roll;
b. begin first improvements to pulp machine (drying and head-box);
c. add a new HCE evaporator train; install a new HCE blow heat recovery system to control all HCE cells;
d. add a new HCE cell;
e. install a new HCE washer; begin second improvements to pulp machine (drying and speed increase); and,
f. install a new post-HCE washer.

The permittee shall obtain prior written approval for any substantial changes to the work described above and in the application for this project.

D.4. Within fourteen (14) days of completing each of the above stages of work, the permittee shall provide a written notice of the following:

a. type of work;
b. date completed;
c. deviations form original proposal; and,
d. a discussion of any emissions impacts.

D.5. Attached to each required Annual Operating Report, the permittee shall provide a summary of the following to the compliance authority:

a. a summary of work performed to date;
b. a summary of work remaining;
c. a preliminary schedule for completing any remaining work; and,
d. the current production capacity of the mill (ADMT per year).

D.6. Performance tests.
a. Prior to increasing plant production beyond 162,000 ADMT per year, the permittee shall install a new HCE blow heat recovery system designed to reduce VOC emissions by 60% from all HCE cells. Upon successful completion of this system, the permittee shall conduct an engineering study to determine the effectiveness of this system in capturing and reducing VOC emissions to achieve designed efficiency . A test protocol shall be submitted to the Department for review and approval prior to commencing the engineering study. Within 60 days of completing the engineering study, the permittee shall submit a report summarizing: the final installed design, material flow rates, emissions, emissions capture, emissions control, and any necessary adjustments.

[Rule 62-4.070(3), F.A.C.]

E. <u>Miscellaneous</u>.

E.1. Report of Actual Emissions. The permittee shall maintain and submit actual annual emissions for a period of 5 years following completion of each project phase. Emissions related to demand growth that could have been accommodated prior to the project must be shown and discussed. This requirement shall be fulfilled by submittal of a report in conjunction with the required Annual Operating Report.

[Rule 62-4.070(3) and 62-212.400(5), F.A.C.]

E.2. Testing While Burning Tires. A one-time test shall be conducted while burning the maximum percentage of tires expected using EPA Method 29 pursuant to 40 CFR 60, Appendix A, and Chapter 62-297, F.A.C.

[Rule 62-4.070(3) and Chapter 62-297, F.A.C.; and, 40 CFR 60, Appendix A]

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SPECIFIC CONDITIONS:

F. Bleach Plant.

F.1. The dissolving-grade bleaching system shall achieve compliance with the bleach plant provisions of 40 CFR 63.445 *as expeditiously as practicable*, but in no event later than 3 years from the issuance of this air construction permit.

[40 CFR 63.440(d)(2) and 63.445]

Attachment "40 CFR 60, Subpart A"

General Provisions

40 CFR 60.1 Applicability.

(a) Except as provided in 40 CFR 60 subparts B and C, the provisions of this part apply to the owner or operator of any stationary source which contains an affected facility, the construction or modification of which is commenced after the date of publication in this part of any standard (or, if earlier, the date of publication of any proposed standard) applicable to that facility.
(b) Any new or revised standard of performance promulgated pursuant to section 111(b) of the Act shall apply to the owner or operator of any stationary source which contains an affected facility, the construction or modification of which is commenced
after the date of publication in this part of such new or revised standard (or, if earlier, the date of publication of any proposed standard) applicable to that facility.
(c) In addition to complying with the provisions of this part, the owner or operator of an affected facility may be required to obtain an operating permit issued to stationary sources by an authorized State air pollution controlagency or by the Administrator of the U.S. Environmental Protection Agency (EPA) pursuant to Title V of the Clean Air Act (CAA) as amended November 15, 1990 (42 U.S.C. 7661).
[Rule 62-204.800, F.A.C.; and, 40 CFR 60.1(a), (b) and (c)]

40 CFR 60.2 Definitions.

(a) *Administrator* means the Administrator of the Environmental Protection Agency or the Secretary or the Secretary's designee.
[Rule 62-204.800(7)(a), F.A.C.; and, 40 CFR 60.2]

40 CFR 60.7 Notification and record keeping.

(a) The owner or operator subject to the provisions of this part shall furnish the Administrator written notification as follows:

(1) A notification of the date construction (or reconstruction as defined under 40 CFR 60.15) of an affected facility is commenced postmarked no later than 30 days after such date. This requirement shall not apply in the case of mass-produced facilities which are purchased in completed form.
(2) A notification of the anticipated date of initial startup of an affected facility postmarked not more than 60 days nor less than 30 days prior to such date.
(3) A notification of the actual date of initial startup of an affected facility postmarked within 15 days after such date.
(4) A notification of any physical or operational change to an existing facility which may increase the emission rate of any air pollutant to which a standard applies, unless that change is specifically exempted under an applicable subpart or in 40 CFR 60.14(e). This notice shall be postmarked 60 days or as soon as practicable before the change is commenced and shall include information describing the precise nature of the change, present and proposed emission control systems, productive capacity of the facility before and after the change, and the expected completion date of the change. The Administrator may request additional relevant information subsequent to this notice.
(5) A notification of the date upon which demonstration of the continuous monitoring system performance commences in accordance with 40 CFR 60.13(c). Notification shall be postmarked not less than 30 days prior to such date.

(6) A notification of the anticipated date for conducting the opacity observations required by 40 CFR 60.11(e)(1) of this part. The notification shall also include, if appropriate, a request for the Administrator to provide a visible emissions reader during a performance test. The notification shall be postmarked not less than 30 days prior to such date.

(7) A notification that continuous opacity monitoring system data results will be used to determine compliance with the applicable opacity standard during a performance test required by 40 CFR 60.8 in lieu of Method 9 observation data as allowed by 40 CFR 60.11(e)(5) of 40 CFR 60. This notification shall be postmarked not less than 30 days prior to the date of the performance test.

(b) The owner or operator subject to the provisions of this part shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of an affected facility; any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or monitoring device is inoperative.

(c) The owner or operator required to install a continuous monitoring system (CMS) or monitoring device shall submit an excess emissions and monitoring systems performance report (excess emissions are defined in applicable subparts) and/or a summary report form (see 40 CFR 60.7(d) to the Administrator semiannually, except when: more frequent reporting is specifically required by an applicable subpart; or the CMS data are to be used directly for compliance determination, in which case quarterly reports shall be submitted; or the Administrator, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. All reports shall be postmarked by the 30th day following the end of each calendar half (or quarter, as appropriate). Written reports of excess emissions shall include the following information:

(1) The magnitude of excess emissions computed in accordance with 40 CFR 60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the reporting period.

(2) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken or preventative measures adopted.

(3) The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.

(4) When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report.

(d) The summary report form shall contain the information and be in the format shown in Figure 1 unless otherwise specified by the Administrator. One summary report form shall be submitted for each pollutant monitored at each affected facility.

(1) If the total duration of excess emissions for the reporting period is less than 1 percent of the total operating time for the reporting period and CMS downtime for the reporting period is less than 5 percent of the total operating time for the reporting period, only the summary report form shall be submitted and the excess emission report described in 40 CFR 60.7(c) need not be submitted unless requested by the Administrator.

(2) If the total duration of excess emissions for the reporting period is 1 percent or greater of the total operating time for the reporting period or the total CMS downtime for the reporting period is 5 percent or greater of the total operating time for the reporting period, the summary report form and the excess emission report described in 40 CFR 60.7(c) shall both be submitted.

[See Attached Figure 1-Summary Report-Gaseous and Opacity Excess Emission and Monitoring System Performance]

(e) The owner or operator subject to the provisions of this part shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by this part recorded in a permanent form suitable for inspection. The file shall be retained for at least two years following the date of such measurements, maintenance, reports, and records.
(f) If notification substantially similar to that in 40 CFR 60.7(a) is required by any other State or local agency, sending the Administrator a copy of that notification will satisfy the requirements of 40 CFR 60.7(a).
(g) Individual subparts of this part may include specific provisions which clarify or make inapplicable the provisions set forth in this section.
[Rule 62-204.800, F.A.C.; and, 40 CFR 60.7(a), (b), (c), (d), (e), (f) and (g)]

40 CFR 60.8 Performance tests.

(a) Within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of such facility and at such other times as may be required by the Administrator under section 114 of the Act, the owner or operator of such facility shall conduct performance test(s) and furnish the Administrator a written report of the results of such performance test(s).
(b) Performance tests shall be conducted and data reduced in accordance with the test methods and procedures contained in each applicable subpart unless the Administrator (1) specifies or approves, in specific cases, the use of a reference method with minor changes in methodology, (4) waives the requirement for performance tests because the owner or operator of a source has demonstrated by other means to the Administrator's satisfaction that the affected facility is in compliance with the standard, or (5) approves shorter sampling times and smaller sample volumes when necessitated by process variables or other factors. Nothing in 40 CFR 60.8 shall be construed to abrogate the Administrator's authority to require testing under section 114 of the Act.
(c) Performance tests shall be conducted under such conditions as the Administrator shall specify to the plant operator based on representative performance of the affected facility. The owner or operator shall make available to the Administrator such records as may be necessary to determine the conditions of the performance tests. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a performance test nor shall emissions in excess of the level of the applicable emission limit during periods of startup, shutdown, and malfunction be considered a violation of the applicable emission limit unless otherwise specified in the applicable standard.
(e) The owner or operator of an affected facility shall provide, or cause to be provided, performance testing facilities as follows:

(1) Sampling ports adequate for test methods applicable to such facility. This includes (i) constructing the air pollution control system such that volumetric flow rates and pollutant emission rates can be accurately determined by applicable test methods and procedures and (ii) providing a stack or duct free of cyclonic flow during performance tests, as demonstrated by applicable test methods and procedures.
(2) Safe sampling platform(s).
(3). Safe access to sampling platform(s).
(4) Utilities for sampling and testing equipment.

(f) Unless otherwise specified in the applicable subpart, each performance test shall consist of three separate runs using the applicable test method. Each run shall be conducted for the time and under the conditions specified in the applicable standard. For the purpose of determining compliance with an applicable standard, the arithmetic means of results of the three runs shall apply. In the event that a sample is accidentally lost or conditions occur in which one of the three runs must be discontinued because of forced shutdown, failure of an irreplaceable portion of the sample train, extreme meteorological conditions, or other circumstances, beyond the owner or operator's control, compliance may, upon the Administrator's approval, be determined using the arithmetic mean of the results of the two other runs.
[Rule 62-204.800, F.A.C.; and, 40 CFR 60.8(a), (b)(1), (4) & (5), (c), (e) and (f)]

40 CFR 60.10 State authority.

The provisions of 40 CFR 60 shall not be construed in any manner to preclude any State or political subdivision thereof from:
(a) Adopting and enforcing any emission standard or limitation applicable to an affected facility, provided that such emission standard or limitation is not less stringent than the standard applicable to such facility.
(b) Requiring the owner or operator of an affected facility to obtain permits, licenses, or approvals prior to initiating construction, modification, or operation of such facility.
[Rule 62-204.800, F.A.C.; and; 40 CFR 60.10(a) and (b)].

40 CFR 60.11 Compliance with standards and maintenance requirements.

(a) Compliance with standards in this part, other than opacity standards, shall be determined by performance tests established by 40 CFR 60.8, unless otherwise specified in the applicable standard.
(b) Compliance with opacity standards in this part shall be determined by conducting observations in accordance with Reference Method 9 in appendix A of this part, any alternative method that is approved by the Administrator, or as provided in 40 CFR 60.11(e)(5). For purposes of determining initial compliance, the minimum total time of observations shall be 3 hours (30 6-minute averages) for the performance test or other set of observations (meaning those fugitive-type emission sources subject only to an opacity standard).
(c) The opacity standards set forth in this part shall apply at all times except during periods of startup, shutdown, malfunction, and as otherwise provided in the applicable standard.
(d) At all times, including periods of startup, shutdown, and malfunction, owners and operators shall, to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.
(e)(1) For the purpose of demonstrating initial compliance, opacity observations shall be conducted concurrently with the initial performance test required in 40 CFR 60.8 unless one of the following conditions apply. If no performance test under 40 CFR 60.8 is required, then opacity observations shall be conducted within 60 days after achieving the maximum production rate at which the affected facility will be operated but no later than 180 days after initial startup of the facility. If visibility or other conditions prevent the opacity observations from being conducted concurrently with the initial performance test required under 40 CFR 60.8, the source owner or operator shall reschedule the opacity observations as soon after the initial performance test as possible, but not later than 30 days thereafter, and shall advise the Administrator of the rescheduled date. In these cases, the 30-day prior notification to the Administrator required in 40 CFR 60.7(a)(6) shall be waived. The rescheduled opacity observations shall be conducted (to the extent possible) under the same operating conditions that existed during the initial performance test conducted under 40 CFR 60.8. The visible emissions observer shall determine whether visibility or other conditions prevent the opacity observations from being made concurrently with the initial performance test in accordance with procedures contained in Reference Method 9 of appendix B of this part. Opacity readings of portions of plumes which contain condensed, uncombined water vapor shall not be used for purposes of determining compliance with opacity standards. The owner or operator of an affected facility shall make available, upon request by the Administrator, such records as may be necessary to determine the conditions under which the visual observations were made and shall provide evidence indicating proof of current visible observer emission certification. Except as provided in 40 CFR 60.11(e)(5), the results of continuous monitoring by transmissometer which indicate that the opacity at the time visual observations were made was not in excess of the standard are probative but not conclusive evidence of the actual opacity of an emission, provided that the source shall meet the burden of proving that the instrument used meets (at the time of the alleged violation) Performance Specification 1 in appendix B of 40 CFR 60, has been properly maintained and (at the time of the alleged violation) that the resulting data have not been altered in any way.

(2) Except as provided in 40 CFR 60.11(e)(3), the owner or operator of an affected facility to which an opacity standard in this part applies shall conduct opacity observations in accordance with 40 CFR 60.11(b), shall record the opacity of emissions, and shall report to the Administrator the opacity results along with the results of the initial performance test required under 40 CFR 60.8. The inability of an owner or operator to secure a visible emissions observer shall not be considered a reason for not conducting the opacity observations concurrent with the initial performance test.
(3) The owner or operator of an affected facility to which an opacity standard in this part applies may request the Administrator to determine and to record the opacity of emissions from the affected facility during the initial performance test and at such times as may be required. The owner or operator of the affected facility shall report the opacity results. Any request to the Administrator to determine and to record the opacity of emissions from an affected facility shall be included in the notification required in 40 CFR 60.7(a)(6). If, for some reason, the Administrator cannot determine and record the opacity of emissions from the affected facility during the performance test, then the provisions of 40 CFR 60.7(e)(1) shall apply.
(4) The owner or operator of an affected facility using a continuous opacity monitor (transmissometer) shall record the monitoring data produced during the initial performance test required by 40 CFR 60.8 and shall furnish the Administrator a written report of the monitoring results along with Method 9 and 40 CFR 60.8 performance test results.
(5) The owner or operator of an affected facility subject to an opacity standard may submit, for compliance purposes, continuous opacity monitoring system (COMS) data results produced during any performance test required under 40 CFR 60.8 in lieu of Method 9 observation data. If an owner or operator elects to submit COMS data for compliance with the opacity standard, he shall notify the Administrator of that decision, in writing, at least 30 days before any performance test required under 40 CFR 60.8 is conducted. Once the owner or operator of an affected facility has notified the Administrator to that effect, the COMS data results will be used to determine opacity compliance during subsequent tests required under 40 CFR 60.8 until the owner or operator notifies the Administrator, in writing, to the contrary. For the purpose of determining compliance with the opacity standard during a performance test required under 40 CFR 60.8 using COMS data, the minimum total time of COMS data collection shall be averages of all 6-minute continuous periods within the duration of the mass emission performance test. Results of the COMS opacity determinations shall be submitted along with the results of the performance test required under 60.8. The owner or operator of an affected facility using a COMS for compliance purposes is responsible for demonstrating that the COMS meets the requirements specified in 40 CFR 60.13(c), that the COMS has been properly maintained and operated, and that the resulting data have not been altered in any way. If COMS data results are submitted for compliance with the opacity standard for a period of time during which Method 9 data indicates noncompliance, the Method 9 data will be used to determine opacity compliance.
(6) Upon receipt from an owner or operator of the written reports of the results of the performance tests required by 40 CFR 60.8, the opacity observation results and observer certification required by 40 CFR 60.11(e)(1), and the COMS results, if applicable, the Administrator will make a finding concerning compliance with opacity and other applicable standards. If COMS data results are used to comply with an opacity standard, only those results are required to be submitted along with the performance test results required by 40 CFR 60.8. If the Administrator finds that an affected facility is in compliance with all applicable standards for which performance tests are conducted in accordance with 40 CFR 60.8 of this part but during the time such performance tests are being conducted fails to meet any applicable opacity standard, the shall notify the owner or operator and advise him that he may petition the Administrator within 10 days of receipt of notification to make appropriate adjustment to the opacity standard for the affected facility.
(7) The Administrator will grant such a petition upon a demonstration by the owner or operator that the affected facility and associated air pollution control equipment was operated and maintained in a manner to minimize the opacity of emissions during the performance tests; that the performance tests were performed under the conditions established by the Administrator; and that the affected facility and associated air pollution control equipment were incapable of being adjusted or operated to meet the applicable opacity standard.

(8) The Administrator will establish an opacity standard for the affected facility meeting the above requirements at a level at which the source will be able, as indicated by the performance and opacity tests, to meet the opacity standard at all times during which the source is meeting the mass or concentration emission standard. The Administrator will promulgate the new opacity standard in the Federal Register.

(f) Special provisions set forth under an applicable subpart of 40 CFR 60 shall supersede any conflicting provisions of 40 CFR 60.11.

(g) For the purpose of submitting compliance certifications or establishing whether or not a person has violated or is in violation of any standard in this part, nothing in this part shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.

[Rule 62-204.800, F.A.C.; and, 40 CFR 60.11(a), (b), (c), (d), (e), (f) and (g)]

40 CFR 60.12 Circumvention.

No owner or operator subject to the provisions of this part shall build, erect, install, or use any article, machine, equipment or process, the use of which conceals an emission which would otherwise constitute a violation of an applicable standard. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with an opacity standard or with a standard which is based on the concentration of a pollutant in the gases discharged to the atmosphere.

[Rule 62-204.800, F.A.C.; and, 40 CFR 60.12]

40 CFR 60.13 Monitoring requirements.

(a) For the purposes of this section, all continuous monitoring systems required under applicable subparts shall be subject to the provisions of this section upon promulgation of performance specifications for continuous monitoring systems under appendix B of 40 CFR 60 and, if the continuous monitoring system is used to demonstrate compliance with emission limits on a continuous basis, appendix F to 40 CFR 60, unless otherwise specified in an applicable subpart or by the Administrator. Appendix F is applicable December 4, 1987.

(b) All continuous monitoring systems and monitoring devices shall be installed and operational prior to conducting performance tests under 40 CFR 60.8. Verification of operational status shall, as a minimum, include completion of the manufacturer's written requirements or recommendations for installation, operation, and calibration of the device.

(c) If the owner or operator of an affected facility elects to submit continuos opacity monitoring system (COMS) data for compliance with the opacity standard as provided under 40 CFR 60.11(e)(5), he/she shall conduct a performance evaluation of the COMS as specified in Performance Specification 1, appendix B, of 40 CFR 60 before the performance test required under 40 CFR 60.8 is conducted. Otherwise, the owner or operator of an affected facility shall conduct a performance evaluation of the COMS or continuous emission monitoring system (CEMS) during any performance test required under 40 CFR 60.8 or within 30 days thereafter in accordance with the applicable performance specification in appendix B of 40 CFR 60. The owner or operator of an affected facility shall conduct COMS or CEMS performance evaluations at such other times as may be required by the Administrator under section 114 of the Act.

(1) The owner or operator of an affected facility using a COMS to determine opacity compliance during any performance test required under 40 CFR 60.8 and as described in 40 CFR 60.11(e)(5), shall furnish the Administrator two or, upon request, more copies of a written report of the results of the COMS performance evaluation described in 40 CFR 60.13(c) at least 10 days before the performance test required under 40 CFR 60.8 is conducted.

(2) Except as provided in 40 CFR 60.13(c)(1), the owner or operator of an affected facility shall furnish the Administrator within 60 days of completion two or, upon request, more copies of a written report of the results of the performance evaluation.

(d)(1) Owners and operators of all continuous emission monitoring systems installed in accordance with the provisions of this part shall check the zero (or low-level value between 0 and 20 percent of span value) and span (50 to 100 percent of span value) calibration drifts at least once daily in accordance with a written procedure. The zero and span shall, as a minimum, be adjusted whenever the 24-hour zero drift or 24-hour span drift exceeds two times the limits of the applicable performance specifications in appendix B. The system must allow the amount of excess zero and span drift measured at the 24-hour interval checks to be recorded and quantified, whenever specified. For continuous monitoring systems measuring opacity of emissions, the optical surfaces exposed to the effluent gases shall be cleaned prior to performing the zero and span drift adjustments except that for systems using automatic zero adjustments. The optical surfaces shall be cleaned when the cumulative automatic zero compensation exceeds 4 percent opacity.

(2) Unless otherwise approved by the Administrator, the following procedures shall be followed for continuous monitoring systems measuring opacity of emissions. Minimum procedures shall include a method for producing a simulated zero opacity condition and an upscale (span) opacity condition using a certified neutral density filter or other related technique to produce a known obscuration of the light beam. Such procedures shall provide a system check of the analyzer internal optical surfaces and all electronic circuitry including the lamp and photo detector assembly.

(e) Except for system breakdowns, repairs, calibration checks, and zero and span adjustments required under 40 CFR 60.13(d), all continuous monitoring systems shall be in continuous operation and shall meet minimum frequency of operation requirements as follows:

(1) All continuous monitoring systems referenced by 40 CFR 60.13(c) for measuring opacity of emissions shall complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period.

(2) All continuous monitoring systems referenced by 40 CFR 60.13(c) for measuring emissions, except opacity, shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

(f) All continuous monitoring systems or monitoring devices shall be installed such that representative measurements of emissions or process parameters from the affected facility are obtained. Additional procedures for location of continuous monitoring systems contained in the applicable Performance Specifications of appendix B of 40 CFR 60 shall be used.

(g) When the effluents from a single affected facility or two or more affected facilities subject to the same emission standards are combined before being released to the atmosphere, the owner or operator may install applicable continuous monitoring systems on each effluent or on the combined effluent. When the affected facilities are not subject to the same emission standards, separate continuous monitoring systems shall be installed on each effluent. When the effluent from one affected facility is released to the atmosphere through more than one point, the owner or operator shall install an applicable continuous monitoring system on each separate effluent unless the installation of fewer systems is approved by the Administrator. When more than one continuous monitoring system is used to measure the emissions from one affected facility (e.g., multiple breechings, multiple outlets), the owner or operator shall report the results as required from each continuous monitoring system.

(h) Owners or operators of all continuous monitoring systems for measurement of opacity shall reduce all data to 6-minute averages and for continuous monitoring systems other than opacity to 1-hour averages for time periods as defined in 40 CFR 60.2. Six-minute opacity averages shall be calculated from 36 or more data points equally spaced over each 6-minute period. For continuous monitoring systems other than opacity, 1-hour averages shall be computed from four or more data points equally spaced over each 1-hour period. Data recorder during periods of continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments shall not be included in the data averages computed under this paragraph. An arithmetic or integrated average of all data may be used. The data may be recorded in reduced or non reduced form (e.g., ppm pollutant and percent O2 or ng/J of pollutant). All excess emissions shall be converted into units of the standard using the applicable conversion procedures specified in subparts. After conversion into units of the standard, the data may be rounded to the same number of significant digits as used in the applicable subparts to specify the emission limit (e.g., rounded to the nearest 1 percent opacity).

(i) After receipt and consideration of written application, the Administrator may approve alternatives to any monitoring procedures or requirements of this part including, but not limited to the following:

(1) Alternative monitoring requirements when installation of a continuous monitoring system or monitoring device specified by this part would not provide accurate measurements due to liquid water or other interferences caused by substances with the effluent gases.

(2) Alternative monitoring requirements when the affected facility is infrequently operated.

(3) Alternative monitoring requirements to accommodate continuous monitoring systems that require additional measurements to correct for stack moisture conditions.

(4) Alternative locations for installing continuous monitoring systems or monitoring devices when the owner or operator can demonstrate that installation at alternate locations will enable accurate and representative measurements.

(5) Alternative methods of converting pollutant concentration measurements to units of the standards.

(6) Alternative procedures for performing daily checks of zero and span drift that do not involve use of span gases or test cells.

(7) Alternatives to the A.S.T.M. test methods or sampling procedures specified by any subpart.

(8) Alternative continuous monitoring systems that do not meet the design or performance requirements in Performance Specification 1, appendix B, but adequately demonstrate a definite and consistent relationship between its measurements and the measurements of opacity by a system complying with the requirements in Performance Specification 1. The Administrator may require that such demonstration be performed for each affected facility.

(9) Alternative monitoring requirements when the effluent from a single affected facility or the combined effluent from two or more affected facilities are released to the atmosphere through more than one point.

(j) An alternative to the relative accuracy test specified in Performance Specification 2 of appendix B may be requested as follows:

(1) An alternative to the reference method tests for determining relative accuracy is available for sources with emission rates demonstrated to be less than 50 percent of the applicable standard. A source owner or operator may petition the Administrator to waive the relative accuracy test in section 7 of Performance Specification 2 and substitute the procedures in section 10 if the results of a performance test conducted according to the requirements in 40 CFR 60.8 of this subpart or other tests performed following the criteria in 40 CFR 60.8 demonstrate that the emission rate of the pollutant of interest in the units of the applicable standard is less than 50 percent of the applicable standard. For sources subject to standards expressed as control efficiency levels, a source owner or operator may petition the Administrator to waive the relative accuracy test and substitute the procedures in section 10 of Performance Specification 2 if the control device exhaust emission rate is less than 50 percent of the level needed to meet the control efficiency requirement. The alternative procedures do not apply if the continuous emission monitoring system is used to determine compliance continuously with the applicable standard. The petition to waive the relative accuracy test shall include a detailed description of the procedures to be applied. Included shall be location and procedure for conducting the alternative, the concentration or response levels of the alternative RA materials, and the other equipment checks included in the alternative procedure. The Administrator will review the petition for completeness and applicability. The determination to grant a waiver will depend on the intended use of the CEMS data (e.g., data collection purposes other than NSPS) and may require specifications more stringent than in Performance Specification 2 (e.g., the applicable emission limit is more stringent than NSPS).

(2) The waiver of a CEMS relative accuracy test will be reviewed and may be rescinded at such time following successful completion of the alternative RA procedure that the CEMS data indicate the source emissions approaching the level of the applicable standard. The criterion for reviewing the waiver is the collection of CEMS data showing that emissions have exceeded 70 percent of the applicable standard for seven, consecutive, averaging periods as specified by the applicable regulation(s). For sources subject to standards expressed as control efficiency levels, the criterion for reviewing the waiver is the collection of CEMS data showing that exhaust emissions have exceeded 70 percent of the level needed to meet the control efficiency requirement for seven, consecutive, averaging periods as specified by the applicable regulation(s) [e.g., 40 CFR 60.45(g)(2) and 40 CFR 60.45(g)(3), 40 CFR 60.73(e), and 40 CFR 60.84(e)]. It is the

responsibility of the source operator to maintain records and determine the level of emissions relative to the criterion on the waiver of relative accuracy testing. If this criterion is exceeded, the owner or operator must notify the Administrator within 10 days of such occurrence and include a description of the nature and cause of the increasing emissions. The Administrator will review the notification and may rescind the waiver and require the owner or operator to conduct a relative accuracy test of the CEMS as specified in section 7 of Performance Specification 2.

[Rule 62-204.800, F.A.C.; and, 40 CFR 60.13(a) thru (j)].

40 CFR 60.14 Modification.

(a) Except as provided under 40 CFR 60.14(e) and 40 CFR 60.14(f), any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies shall be considered a modification within the meaning of section 111 of the Act. Upon modification, an existing facility shall become an affected facility for each pollutant to which a standard applies and for which there is an increase in the emission rate to the atmosphere.

(b) Emission rate shall be expressed as kg/hr (lbs/hour) of any pollutant discharged into the atmosphere for which a standard is applicable. The Administrator shall use the following to determine emission rate:

(1) Emission factors as specified in the latest issue of "Compilation of Air Pollutant Emission Factors", EPA Publication No. AP-42, or other emission factors determined by the Administrator to be superior to AP-42 emission factors, in cases where utilization of emission factors demonstrate that the emission level resulting from the physical or operational change will either clearly increase or clearly not increase.

(2) Material balances, continuous monitor data, or manual emission tests in cases where utilization of emission factors as referenced in 40 CFR 60.14(b)(1) does not demonstrate to the Administrator's satisfaction whether the emission level resulting from the physical or operational change will either clearly increase or clearly not increase, or where an owner or operator demonstrates to the Administrator's satisfaction that there are reasonable grounds to dispute the result obtained by the Administrator utilizing emission factors as referenced in 40 CFR 60.14(b)(1) . When the emission rate is based on results from manual emission tests or continuous monitoring systems, the procedures specified in 40 CFR 60 appendix C of 40 CFR 60 shall be used to determine whether an increase in emission rate has occurred. Tests shall be conducted under such conditions as the Administrator shall specify to the owner or operator based on representative performance of the facility. At least three valid test runs must be conducted before and at least three after the physical or operational change. All operating parameters which may affect emissions must be held constant to the maximum feasible degree for all test runs.

(c) The addition of an affected facility to a stationary source as an expansion to that source or as a replacement for an existing facility shall not by itself bring within the applicability of this part any other facility within that source.

(d) [Reserved]

(e) The following shall not, by themselves, be considered modifications under this part:

(1) Maintenance, repair, and replacement which the Administrator determines to be routine for a source category, subject to the provisions of 40 CFR 60.14(c) and 40 CFR 60.15.

(2) An increase in production rate of an existing facility, if that increase can be accomplished without a capital expenditure on that facility.

(3) An increase in the hours of operation.

(4) Use of an alternative fuel or raw material if, prior to the date any standard under this part becomes applicable to that source type, as provided by 40 CFR 60.1, the existing facility was designed to accommodate that alternative use. A facility shall be considered to be designed to accommodate an alternative fuel or raw material if that use could be accomplished under the facility's construction specifications as amended prior to the change. Conversion to coal required for energy considerations, as specified in section 111(a)(8) of the Act, shall not be considered a modification.

(5) The addition or use of any system or device whose primary function is the reduction of air pollutants, except when an emission control system is removed or is replaced by a system which the Administrator determines to be less environmentally beneficial.

(6) The relocation or change in ownership of an existing facility.

(f) Special provisions set forth under an applicable subpart of this part shall supersede any conflicting provisions of this section.

(g) Within 180 days of the completion of any physical or operational change subject to the control measures specified in 40 CFR 60.14(a), compliance with all applicable standards must be achieved.

[Rule 62-204.800, F.A.C.; and, 40 CFR 60.14(a) thru (g)].

40 CFR 60.15 Reconstruction.

(a) An existing facility, upon reconstruction, becomes an affected facility, irrespective of any change in emission rate.

(b) "Reconstruction" means the replacement of components of an existing facility 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 entirely new facility, and

(2) It is technologically and economically feasible to meet the applicable standards set forth in this part.

(c) "Fixed capital cost"' means the capital needed to provide all the depreciable components.

(d) If an owner or operator of an existing facility proposes to replace components, and the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, he shall notify the Administrator of the proposed replacements. The notice must be postmarked 60 days (or as soon as practicable) before construction of the replacements is commenced and must include the following information:

(1) Name and address of the owner or operator.

(2) The location of the existing facility.

(3) A brief description of the existing facility and the components which are to be replaced.

(4) A description of the existing air pollution control equipment and the proposed air pollution control equipment.

(5) An estimate of the fixed capital cost of the replacements and of constructing a comparable entirely new facility.

(6) The estimated life of the existing facility after the replacements.

(7) A discussion of any economic or technical limitations the facility may have in complying with the applicable standards of performance after the proposed replacements.

(e) The Administrator will determine, within 30 days of the receipt of the notice required by 40 CFR 60.15(d) and any additional information he may reasonably require, whether the proposed replacement constitutes reconstruction.

(f) The Administrator's determination under 40 CFR 60.15(e) shall be based on:

(1) The fixed capital cost of the replacements in comparison to the fixed capital cost that would be required to construct a comparable entirely new facility;

(2) The estimated life of the facility after the replacements compared to the life of a comparable entirely new facility;

(3) The extent to which the components being replaced cause or contribute to the emissions from the facility; and

(4) Any economic or technical limitations on compliance with applicable standards of performance which are inherent in the proposed replacements.

(g) Individual subparts of this part may include specific provisions which refine and delimit the concept of reconstruction set forth in this section.

[Rule 62-204.800, F.A.C.; and, 40 CFR 60.15(a) thru (g)].

Tables to Subpart DDDDD of Part 63

TABLE 1 TO SUBPART DDDDD OF PART 63.—EMISSION LIMITS AND WORK PRACTICE STANDARDS

As stated in § 63.7500, you must comply with the following applicable emission limits and work practice standards:

If your boiler or process heater is in this subcategory	For the following pollutants	You must meet the following emission limits and work practice standards
1. New or reconstructed large solid fuel	a. Particulate Matter (or Total Selected Metals).	0.025 lb per MMBtu of heat input; or (0.0003 lb per MMBtu of heat input).
	b. Hydrogen Chloride	0.02 lb per MMBtu of heat input.
	c. Mercury	0.000003 lb per MMBtu of heat input.
	d. Carbon Monoxide	400 ppm by volume on a dry basis corrected to 7 percent oxygen (30-day rolling average for units 100 MMBtu/hr or greater, 3-run average for units less than 100 MMBtu/hr).
2. New or reconstructed limited use solid fuel	a. Particulate Matter (or Total Selected Metals).	0.025 lb per MMBtu of heat input; or (0.0003 lb per MMBtu of heat input).
	b. Hydrogen Chloride	0.02 lb per MMBtu of heat input.
	c. Mercury	0.000003 lb per MMBtu of heat input.
	d. Carbon Monoxide	400 ppm by volume on a dry basis corrected to 7 percent oxygen (3-run average).
3. New or reconstructed small solid fuel	a. Particulate Matter (or Total Selected Metals).	0.025 lb per MMBtu of heat input; or (0.0003 lb per MMBtu of heat input).
	b. Hydrogen Chloride	0.02 lb per MMBtu of heat input.
	c. Mercury	0.000003 lb per MMBtu of heat input.
4. New reconstructed large liquid fuel	a. Particulate Matter	0.03 lb per MMBtu of heat input.
	b. Hydrogen Chloride	0.0005 lb per MMBtu of heat input.
	c. Carbon Monoxide	400 ppm by volume on a dry basis corrected to 3 percent oxygen (30-day rolling average for units 100 MMBtu/hr or greater, 3-run average for units less than 100 MMBtu/hr).
5. New or reconstructed limited use liquid fuel	a. Particulate Matter	0.03 lb per MMBtu of heat input.
	b. Hydrogen Chloride	0.0009 lb per MMBtu of heat input.
	c. Carbon Monoxide	400 ppm by volume on a dry basis liquid corrected to 3 percent oxygen (3-run average).
6. New or reconstructed small liquid fuel	a. Particulate Matter	0.03 lb per MMBtu of heat input.
	b. Hydrogen Chloride	0.0009 lb per MMBtu of heat input.
7. New reconstructed large gaseous fuel	Carbon Monoxide	400 ppm by volume on a dry basis corrected to 3 percent oxygen (30-day rolling average for units 100 MMBtu/hr or greater, 3-run average for units less than 100 MMBtu/hr).
8. New or reconstructed limited use gaseous fuel.	Carbon Monoxide	400 ppm by volume on a dry basis corrected to 3 percent oxygen (3-run average).
9. Existing large solid fuel	a. Particulate Matter (or Total Selected Metals).	0.07 lb per MMBtu of heat input; or (0.001 lb per MMBtu of heat input).
	b. Hydrogen Chloride	0.09 lb per MMBtu of heat input.
	c. Mercury	0.000009 lb per MMBtu of heat input.
10. Existing limited use solid fuel	Particulate Matter (or Total Selected Metals)	0.21 lb per MMBtu of heat input; or (0.004 lb per MMBtu of heat input).

TABLE 2 TO SUBPART DDDDD OF PART 63.—OPERATING LIMITS FOR BOILERS AND PROCESS HEATERS WITHPARTICULATE MATTER EMISSION LIMITS

As stated in § 63.7500, you must comply with the applicable operating limits:

If you demonstrate compliance with applicable particulate matter emission limits using	**You must meet these operating limits**
1. Wet scrubber control	a. Maintain the minimum pressure drop and liquid flow-rate at or above the operating levels established during the performance test according to § 63.7530(c) and Table 7 to this subpart that demonstrated compliance with the applicable emission limit for particulate matter.
2. Fabric filter control	a. Install and operate a bag leak detection system according to § 63.7525 and operate the fabric filter such that the bag leak detection system alarm does not sound more than 5 percent of the operating time during each 6-month period; or
	b. This option is for boilers and process heaters that operate dry control systems. Existing boilers and process heaters must maintain opacity to less than or equal to 20 percent (6-minute average) except for one 6-minute period per hour of not more than 27 percent. New boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity (1-hour block average).
3. Electrostatic precipitator control	a. This option is for boilers and process heaters that operate dry control systems. Existing boilers and process heaters must maintain opacity to less than or equal to 20 percent (6-minute average) except for one 6-minute period per hour of not more than 27 percent. New boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity (1-hour block average); or
	b. This option is only for boilers and process heaters that operate additional wet control systems. Maintain the minimum voltage and secondary current or total power input of the electrostatic precipitator at or above the operating limits established during the performance test according to § 63.7530(c) and Table 7 to this subpart that demonstrated compliance with the applicable emission limit for particulate matter.
4. Any other control type	This option is for boilers and process heaters that operate dry control systems. Existing boilers and process heaters must maintain opacity to less than or equal to 20 percent (6-minute average) except for one 6-minute period per hour of not more than 27 percent. New boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity (1-hour block average).

TABLE 3 TO SUBPART DDDDD OF PART 63.—OPERATING LIMITS FOR BOILERS AND PROCESS HEATERS WITH MERCURY EMISSION LIMITS AND BOILERS AND PROCESS HEATERS THAT CHOOSE TO COMPLY WITH THE ALTERNATIVE TOTAL SELECTED METALS EMISSION LIMITS

As stated in § 63.7500, you must comply with the applicable operating limits:

If you demonstrate compliance with applicable mercury and/or total selected metals emission limits using	You must meet these operating limits
1. Wet scrubber control	Maintain the minimum pressure drop and liquid flow-rate at or above the operating levels established during the performance test according to § 63.7530(c) and Table 7 to this subpart that demonstrated compliance with the applicable emission limits for mercury and/or total selected metals.
2. Fabric filter control	a. Install and operate a bag leak detection system according to § 63.7525 and operate the fabric filter such that the bag leak detection system alarm does not sound more than 5 percent of the operating time during a 6-month period; or
	b. This option is for boilers and process heaters that operate dry control systems. Existing sources must maintain opacity to less than or equal to 20 percent (6-minute average) except for one 6-minute period per hour of not more than 27 percent. New sources must maintain opacity to less than or equal to 10 percent opacity (1-hour block average).
3. Electrostatic precipitator control	a. This option is for boilers and process heaters that operate dry control systems. Existing sources must maintain opacity to less than or equal to 20 percent (6-minute average) except for one 6-minute period per hour of not more than 27 percent. New sources must maintain opacity to less than or equal to 10 percent opacity (1-hour block average); or b. This option is only for boilers and process heaters that operate additional wet control systems. Maintain the minimum voltage and secondary current or total power input of the electrostatic precipitator at or above the operating limits established during the performance test according to § 63.7530(c) and Table 7 to this subpart that demonstrated compliance with the applicable emission limits for mercury and/or total selected metals.
4. Dry scrubber or carbon injection control	Maintain the minimum sorbent or carbon injection rate at or above the operating levels established during the performance test according to § 63.7530(c) and Table 7 to this subpart that demonstrated compliance with the applicable emission limit for mercury.
5. Any other control type	This option is only for boilers and process heaters that operate dry control systems. Existing sources must maintain opacity to less than or equal to 20 percent (6-minute average) except for one 6-minute period per hour of not more than 27 percent. New sources must maintain opacity to less than or equal to 10 percent opacity (1-hour block average).
6. Fuel analysis	Maintain the fuel type or fuel mixture such that the mercury and/or total selected metals emission rates calculated according to § 63.7530(d)(4) and/or (5) is less than the applicable emission limits for mercury and/or total selected metals.

TABLE 4 TO SUBPART DDDDD OF PART 63.—OPERATING LIMITS FOR BOILERS AND PROCESS HEATERS WITH HYDROGEN CHLORIDE EMISSION LIMITS

As stated in § 63.7500, you must comply with the following applicable operating limits:

If you demonstrate compliance with applicable hydrogen chloride emission limits using	You must meet these operating limits
1. Wet scrubber control	Maintain the minimum scrubber effluent pH, pressure drop, and liquid flow-rate at or above the operating levels established during the performance test according to § 63.7530(c) and Table 7 to this subpart that demonstrated compliance with the applicable emission limit for hydrogen chloride.
2. Dry scrubber control	Maintain the minimum sorbent injection rate at or above the operating levels established during the performance test according to § 63.7530(c) and Table 7 to this subpart that demonstrated compliance with the applicable emission limit for hydrogen chloride.
3. Fuel analysis	Maintain the fuel type or fuel mixture such that the hydrogen chloride emission rate calculated according to § 63.7530(d)(3) is less than the applicable emission limit for hydrogen chloride.

TABLE 5 TO SUBPART DDDDD OF PART 63.—PERFORMANCE TESTING REQUIREMENTS

As stated in § 63.7520, you must comply with the following requirements for performance test for existing, new or reconstructed affected sources:

To conduct a performance test for the following pollutant	You must	Using
1. Particulate Matter	a. Select sampling ports location and the number of traverse points.	Method 1 in appendix A to part 60 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2F, or 2G in appendix A to part 60 of this chapter.
	c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B in appendix A to part 60 of this chapter, or ASME PTC 19, Part 10 (1981) (IBR, see § 63.14(i)).
	d. Measure the moisture content of the stack gas.	Method 4 in appendix A to part 60 of this chapter.
	e. Measure the particulate matter emission concentration.	Method 5 or 17 (positive pressure fabric filters must use Method 5D) in appendix A to part 60 of this chapter.
	f. Convert emissions concentration to lb per MMBtu emission rates.	Method 19 F-factor methodology in appendix A to part 60 of this chapter.
2. Total selected metals	a. Select sampling ports location and the number of traverse points.	Method 1 in appendix A to part 60 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2F, or 2G in appendix A to part 60 of this chapter.
	c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B in appendix A to part 60 of this chapter, or ASME PTC 19, Part 10 (1981) (IBR, see § 63.14(i)).
	d. Measure the moisture content of the stack gas.	Method 4 in appendix A to part 60 of this chapter.
	e. Measure the particulate matter emission concentration.	Method 29 in appendix A to part 60 of this chapter.
	f. Convert emissions concentration to lb per MMBtu emission rates.	Method 19 F-factor methodology in appendix A to part 60 of this chapter.
3. Hydrogen chloride	a. Select sampling ports location and the number of traverse points.	Method 1 in appendix A to part 60 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2F, or 2G in appendix A to part 60 of this chapter.
	c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B in appendix A to part 60 of this chapter, or ASME PTC 19, Part 10 (1981) (IBR, see § 63.14(i)).
	d. Measure the moisture content of the stack gas.	Method 4 in appendix A to part 60 of this chapter.
	e. Measure the particulate matter emission concentration.	Method 26 or 26A in appendix A to part 60 of this chapter.
	f. Convert emissions concentration to lb per MMBtu emission rates.	Method 19 F-factor methodology in appendix A to part 60 of this chapter.
4. Mercury	a. Select sampling ports location and the number of traverse points	Method 1 in appendix A to part 60 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2F, or 2G in appendix A to part 60 of this chapter.
	c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B in appendix A to part 60 of this chapter, or ASME PTC 19, Part 10 (1981) (IBR, see § 62.14(i)).
	d. Measure the moisture content of the stack gas.	Method 4 in appendix A to part 60 of this chapter.
	e. Measure the particulate matter emission concentration.	Method 29 in appendix A to part 60 of this chapter or Method 101A in appendix B to part 61 of this chapter or ASTM Method D6784–02 (IBR, see § 63.14(b)).
	f. Convert emissions concentration to lb per MMBtu emission rates.	Method 19 F-factor methodology in appendix A to part 60 of this chapter.
5. Carbon Monoxide	a. Select the sampling ports location and the number of traverse points.	Method 1 in appendix A to part 60 of thischapter.
	b. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B in appendix A to part 60 of this chapter, or ASTM D6522–00 (IBR, see § 63.14(b)), or ASME PTC 19, Part 10 (1981) (IBR, see § 63.14(i)).
	c. Measure the moisture content of the stack gas.	Method 4 in appendix A to part 60 of this chapter.
	d. Measure the carbon monoxide emission concentration.	Method 10, 10A, or 10B in appendix A to part 60 of this chapter, or ASTM D6522–00 (IBR, see § 63.14(b)) when the fuel is natural gas.

TABLE 6 TO SUBPART DDDDD OF PART 63—FUEL ANALYSIS REQUIREMENTS

As stated in § 63.7521, you must comply with the following requirements for fuel analysis testing for existing, new or reconstructed affected sources:

To conduct a fuel analysis for the following pollutant	You must	Using
1. Mercury	a. Collect fuel samples	Procedure in § 63.7521(c) or ASTM D2234– 00 □1 (for coal)(IBR, see § 63.14(b)) or ASTM D6323–98 (2003)(for biomass)(IBR, see § 63.14(b)) or equivalent.
	b. Composite fuel samples	Procedure in § 63.7521(d) or equivalent.
	c. Prepare composited fuel samples	SW–846–3050B (for solid samples) or SW– 846–3020A (for liquid samples) or ASTM D2013–01 (for coal) (IBR, see § 63.14(b)) or ASTM D5198–92 (2003) (for biomass)(IBR, see § 63.14(b)) or equivalent.
	d. Determine heat content of the fuel type	ASTM D5865–03a (for coal)(IBR, see § 63.14(b)) or ASTM E711–87 (1996) (for biomass)(IBR, see § 63.14(b)) or equivalent.
	e. Determine moisture content of the fuel type	ASTM D3173–02 (IBR, see § 63.14(b)) or ASTM E871–82 (1998)(IBR, see § 63.14(b)) or equivalent.
	f. Measure mercury concentration in fuel sample.	ASTM D3684–01 (for coal)(IBR, see § 63.14(b)) or SW–846–7471A (for solid samples) or SW–846 7470A (for liquid samples).
	g. Convert concentrations into units of pounds of pollutant per MMBtu of heat content.	
2. Total selected metals	a. Collect fuel samples	Procedure in § 63.7521(c) or ASTM D2234– 00 □1 (for coal)(IBR, see § 63.14(b)) or ASTM D6323–98 (2003) (for biomass)(IBR, see § 63.14(b)) or equivalent.
	b. Composite fuel samples	Procedure in § 63.7521(d) or equivalent.
	c. Prepare composited fuel samples	SW–846–3050B (for solid samples) or SW– 846–3020A (for liquid samples) or ASTM D2013–01 (for coal)(IBR, see § 63.14(b)) or ASTM D5198–92 (2003)(for biomass)(IBR,see § 63.14(b)) or equivalent.
	d. Determine heat content of the fuel type	ASTM D5865–03a (for coal)(IBR, see § 63.14(b)) or ASTM E 711–87 (for biomass)(IBR, see § 63.14(b)) or equivalent.
	e. Determine moisture content of the fuel type	ASTM D3173–02 (IBR, see § 63.14(b)) or ASTM E871 (IBR, see § 63.14(b)) or equivalent.
	f. Measure mercury concentration in fuel sample.	SW–846–6010B or ASTM D3683–94 (2000) (for coal) (IBR, see § 63.14(b)) or ASTM E885–88 (1996) (for biomass)(IBR, see § 63.14(b)).
	g. Convert concentrations into units of pounds of pollutant per MMBtu of heat content.	
3. Hydrogen chloride	a. Collect fuel samples	Procedure in § 63.7521(c) or ASTM D2234 □1 (for coal)(IBR, see § 63.14(b)) or ASTM D6323–98 (2003) (for biomass)(IBR, see § 63.14(b)) or equivalent.
	b. Composite fuel samples	Procedure in § 63.7521(d) or equivalent.
	c. Prepare composited fuel samples	SW–846–3050B (for solid samples) or SW– 846–3020A (for liquid samples) or ASTM D2013–01 (for coal)(IBR, see § 63.14(b)) or ASTM D5198–92 (2003) (for biomass)(IBR, see § 63.14(b)) or equivalent.
	d. Determine heat content of the fuel type	ASTM D5865–03a (for coal)(IBR, see § 63.14(b)) or ASTM E711–87 (1996) (for biomass)(IBR, see § 63.14(b)) or equivalent.
	e. Determine moisture content of the fuel type	ASTM D3173–02 (IBR, see § 63.14(b)) or ASTM E871–82 (1998)(IBR, see § 63.14(b)) or equivalent.
	f. Measure mercury concentration in fuel sample.	SW–846–9250 or ASTM E776–87 (1996) (for biomass)(IBR, see § 63.14(b)) or equivalent.
	g. Convert concentrations into units of pounds of pollutant per MMBtu of heat content.	

TABLE 7 TO SUBPART DDDDD OF PART 63—ESTABLISHING OPERATING LIMITS

As stated in § 63.7520, you must comply with the following requirements for establishing operating limits:

If you have an applicable emission limit for	And your operating limits are based on	You must	Using	According to the following requirements
1. Particulate matter, mercury, or total selected metals.	a. Wet scrubber operating parameters.	i. Establish a site-specific minimum pressure drop and minimum flow rate operating limit according to § 63.7530(c).	(1) Data from the pressure drop and liquid flow rate monitors and the particulate matter, mercury, or total selected metals performance test.	(a) You must collect pressure drop and liquid flowrate data every 15 minutes during the entire period of the performance tests; (b) Determine the average pressure drop and liquid flow-rate for each individual test run in the three-run performance test by computing the average of all the 15-minute readings taken during each test run.
	b. Electrostatic precipitator operating parameters (option only for units with additional wet scrubber control).	i. Establish a site-specific minimum voltage and secondary current or total power input according to § 63.7530(c).	(1) Data from the pressure drop and liquid flow rate monitors and the particulate matter, mercury, or total selected metals performance test.	(a) You must collect voltage and secondary current or total power input data every 15 minutes during the entire period of the performance tests; (b) Determine the average voltage and secondary current or total power input for each individual test run in the three-run performance test by computing the average of all the 15-minute readings taken during each test run.
2. Hydrogen Chloride	a. Wet scrubber operating parameters.	i. Establish a site-specific minimum pressure drop and minimum flow rate operating limit according to § 63.7530(c).	(1) Data from the pH, pressure drop, and liquid flow-rate monitors and the hydrogen chloride performance test.	(a) You must collect pH, pressure drop, and liquid flow-rate data every 15 minutes during the entire period of the performance tests; (b) Determine the average pH, pressure drop, and liquid flow-rate for each individual test run in the three-run performance test by computing the average of all the 15-minute readings taken during each test run.

TABLE 7 TO SUBPART DDDDD OF PART 63—ESTABLISHING OPERATING LIMITS continued:

As stated in § 63.7520, you must comply with the following requirements for establishing operating limits:

	b. Dry scrubber operating parameters.	i. Establish a site-specific minimum sorbent injection rate operating limit according to § 63.7530(c).	(1) Data from the sorbent injection rate monitors and hydrogen chloride performance test.	(a) You must collect sorbent injection rate data every 15 minutes during the entire period of the performance tests; (b) Determine the average sorbent injection rate for each individual test run in the three-run performance test by computing the average of all the 15-minute readings taken during each test run.

TABLE 8 TO SUBPART DDDDD OF PART 63—DEMONSTRATING CONTINUOUS COMPLIANCE

As stated in § 63.7540, you must show continuous compliance with the emission limitations for affected sources according to the following:

If you must meet the following operating limits or work practice standards	You must demonstrate continuous compliance by
1. Opacity	a. Collecting the opacity monitoring system data according to §§ 63.7525(b) and 63.7535; and b. Reducing the opacity monitoring data to 6-minute averages; and c. Maintaining opacity to less than or equal to 20 percent (6-minute average) except for one 6-minute period per hour of not more than 27 percent for existing sources; or maintaining opacity to less than or equal to 10 percent (1-hour block average) for new sources.
2. Fabric Filter Bag Leak Detection Operation	Installing and operating a bag leak detection system according to § 63.7525 and operating the fabric filter such that the requirements in § 63.7540(a)(9) are met.
3. Wet Scrubber Pressure Drop and Liquid Flow-rate	a. Collecting the pressure drop and liquid flow rate monitoring system data according to §§ 63.7525 and 63.7535; and b. Reducing the data to 3-hour block averages; and c. Maintaining the 3-hour average pressure drop and liquid flow-rate at or above the operating limits established during the performance test according to § 63.7530(c).
4. Wet Scrubber pH	a. Collecting the pH monitoring system data according to §§ 63.7525 and 63.7535; and b. Reducing the data to 3-hour block averages; and c. Maintaining the 3-hour average pH at or above the operating limit established during the performance test according to § 63.7530(c).
5. Dry Scrubber Sorbent or Carbon Injection Rate	a. Collecting the sorbent or carbon injection rate monitoring system data for the dry scrubber according to §§ 63.7525 and 63.7535; and b. Reducing the data to 3-hour block averages; and c. Maintaining the 3-hour average sorbent or carbon injection rate at or above the operating limit established during the performance test according to §§ 63.7530(c).
6. Electrostatic Precipitator Secondary Current and Voltage or Total Power Input.	a. Collecting the secondary current and voltage or total power input monitoring system data for the electrostatic precipitator according to §§ 63.7525 and 63.7535; and b. Reducing the data to 3-hour block averages; and c. Maintaining the 3-hour average secondary current and voltage or total power input at or above the operating limits established during the performance test according to §§ 63.7530(c).
7. Fuel Pollutant Content	a. Only burning the fuel types and fuel mixtures used to demonstrate compliance with the applicable emission limit according to § 63.7530(c) or (d) as applicable; and b. Keeping monthly records of fuel use according to § 63.7540(a).

TABLE 9 TO SUBPART DDDDD OF PART 63.—REPORTING REQUIREMENTS

As stated in § 63.7550, you must comply with the following requirements for reports:

You must submit a(n)	The report must contain	You must submit the report
1. Compliance report	a. Information required in § 63.7550(c)(1) through (11); and b. If there are no deviations from any emission limitation (emission limit and operating limit) that applies to you and there are no deviations from the requirements for work practice standards in Table 8 to this subpart that apply to you, a statement that there were no deviations from the emission limitations and work practice standards during the reporting period. If there were no periods during which the CMSs, including continuous emissions monitoring system, continuous opacity monitoring system, and operating parameter monitoring systems, were out-of-control as specified in § 63.8(c)(7), a statement that there were no periods during which the CMSs were out-of-control during the reporting period; and c. If you have a deviation from any emission limitation (emission limit and operating limit) or work practice standard during the reporting period, the report must contain the information in § 63.7550(d). If there were periods during which the CMSs, including continuous emissions monitoring system, continuous opacity monitoring system, and operating parameter monitoring systems, were out-of-control, as specified in § 63.8(c)(7), the report must contain the information in § 63.7550(e); and d. If you had a startup, shutdown, or malfunction during the reporting period and you took actions consistent with your startup, shutdown, and malfunction plan, the compliance report must include the information in § 63.10(d)(5)(i)	Semiannually according to the requirements in § 63.7550(b).
2. An immediate startup, shutdown, and malfunction report if you had a startup, shutdown, or malfunction during the reporting period that is not consistent with your startup, shutdown, and malfunction plan, and the source exceeds any applicable emission limitation in the relevant emission standard.	a. Actions taken for the event; and	i. By fax or telephone within 2 working days after starting actions inconsistent with the plan; and
	b. The information in § 63.10(d)(5)(ii)	ii. By letter within 7 working days after the end of the event unless you have made alternative arrangements with the permitting authority.

Other Attachments Are Available Upon Request

P.E. CERTIFICATION STATEMENT

PERMITTEE

Rayonier Performance Fibers LLC
Fernandina Beach Dissolving Sulfite Pulp Mill
Nassau County, Florida

Draft Air Permit No. 0890004-018-AC
Power Boiler Replacement Project
No. 6 Batch Digester Increase

PROJECT DESCRIPTION

The applicant requests that the digester production limit be increased from 153,205 to 162,000 ADMT per year. At a later date, the applicant intends to install a blow heat recovery system on the vent from the cooking process, which accounts for approximately 80% of the volatile organic compounds (VOC) generated from the bleaching system. The blow heat recovery system will remove approximately 60% of the VOC emissions from the cooking process vent. After the blow heat recovery system is installed, the applicant requests that the production limit be increased from 162,000 to 175,000 ADMT per year. Minor equipment changes and additions are necessary to realize the increased production levels.

The applicant also proposes to permanently shut down Power Boiler Nos. 1 – 3 and install a new bubbling bed boiler (Power Boiler No. 6) with a maximum heat input rate of 525 MMBtu per hour (450 MMBtu per hour, annual average). The new unit will primarily fire bark/wood, tire-derived fuel (TDF) as a supplemental fuel, and No. 6 residual oil as a startup and supplemental fuel. Also, small amounts of on-specification used oil generated on site will be fired for energy recovery. The "new" unit will be a refurbished coal-fired boiler with the following controls: settling chamber (ash hopper); 4-field electrostatic precipitator (ESP); alkaline wet scrubber; staged combustion; flue gas recirculation (FGR); and the capability to add Selective Non-Catalytic Reduction (SNCR) as necessary to comply with the requested NOx standard. The boiler will be subject to NSPS Subpart D, NESHAP Subpart DDDDD, Rule 62-296.410, F.A.C., and emissions caps (CO, NOx, SO_2) pursuant to Rule 62-212.400(2)(g), F.A.C. (Relaxation).

The application is structured such that potential emissions from the "new" boiler net out of PSD preconstruction review due to the shutdown of the old power boilers. The combined projects net out of PSD preconstruction review based on the planned installation of additional pollution controls, requested emissions caps, and the applicant's projected actual emissions. In addition to the applicable regulations, the draft permit includes several conditions to provide reasonable assurance. See the attached Technical Evaluation and Preliminary Determination for a full discussion of the project.

I HEREBY CERTIFY *that the air pollution control engineering features described in the above referenced application and subject to the proposed permit conditions provide reasonable assurance of compliance with applicable provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Chapters 62-4 and 62-204 through 62-297. However, I have not evaluated and I do not certify aspects of the proposal outside of my area of expertise (including, but not limited to, the electrical, mechanical, structural, hydrological, geological, and meteorological features).*

Jeffery F. Koerner, P.E. — 1-26-06
Registration Number: 49441 — (Date)

7000 1670 0013 3110 0093

U.S. Postal Service

CERTIFIED MAIL RECEIPT

(Domestic Mail Only; No Insurance Coverage Provided)

Postage	$	Postmark Here
Certified Fee		
Return Receipt Fee (Encorsement Required)		
Restricted Delivery Fee (Endorsement Required)		

Mr. F. J. Perrett, Environmental Manager
Rayonier Performance Fibers LLC
Fernandina Beach Mill
The Foot of the Gum Tree
Post Office Box 2002
Fernandina Beach, FL 32035-2002

PS Form 3800, May 2000 See Reverse for Instructions

Memorandum Florida Department of Environmental Protection

INTEROFFICE MEMORANDUM

TO: Trina Vielhauer

THRU: Jeff Koerner JK

FROM: Bruce Mitchell BM

DATE: January 25, 2006

SUBJECT: Rayonier Performance Fibers, LLC
Draft Air Constrution Permit
0890004-018-AC

Attached is the Draft Air Construction Permit, Project No. 0890004-018-AC.

The subject of the Air Construction Permit is to initially increase in the facility's production from 153,205 to 162,000 air dried metric ton (ADMT) per consecutive 12-months, rolling total. After successful installation of a new blow heat recovery system to control VOC (volatile organic compounds) emissions from all HCE cells, production may increase to 175,000 ADMT per consecutive 12-months, rolling total. In order to achieve the increases in production, the permittee will also be authorized to perform the following construction and work: add a new HCE (hot caustic extract) washer press roll; begin first improvements to pulp machine (drying and head-box); add a new HCE evaporator train; install a new HCE blow heat recovery system to control all HCE cells; add a new HCE cell; install a new HCE washer; begin second improvements to pulp machine (drying and speed increase); and, install a new post-HCE washer. The new #6 PB is actually an existing used PB (obtained from another mill and built in 1983) and is being altered from a pulverized coal fired PB to a fluidized-bed wood fired PB; and, the emissions unit will replace three existing fuel-oil fired PBs, Nos. 1, 2 and 3.

Today is Day 2 of the permitting clock.

Attachments

TLV/jk/bm

Rayonier

Performance Fibers

Fernandina Mill

January 19, 2006

RECEIVED

JAN 23 2006

BUREAU OF AIR REGULATION

Mr. Jeffery F. Koerner, P. E.
Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, FL 32399-2400

RE: Request to Install the No. 6 Power Boiler and the No. 6 Batch Digester
Air Construction Project No. 08900004-018-AC

Dear Mr. Koerner:

I am responding to the questions in your January 18, 2006 letter in the order in which you have asked them.

Attached is a revised Process Description. You previously requested a process description. We have added to the end of that description many of the answers to your questions and these answers will reference that document.

1. Updated process flow diagram.
See page 9 of attached process description. There we provide separate process flow diagrams for the digester/washer system, the HCE system with blow heat recovery, and evaporator system with the new HCE evaporator train.

2. Provide the appropriate application pages for the HCE evaporators.
Attached.

3. ClO_2 plant versus ClO_2 tower.
At one time we thought we would need a new ClO_2 tower, but now it appears the tower will not be needed. We included in the application for completeness. We wish to remove it from the application. A ClO_2 plant was included in the application but it is clear that we would be purchasing a used plant and can not at this time specify the process. Therefore we are removing the ClO_2 plant from the application as well. It is understood that a separate application would be required for this equipment.

4. Describe the HCE evaporator project, including the pre-HCE thickener, the post HCE washer etc.
The HCE evaporators, the HCE washer press roll and the new post HCE washers are not directly connected. The HCE evaporator simply increases evaporation as the way to prepare HCE for sale. Additional evaporation is needed to accommodate the production increase. The HCE washer press roll has two functions. First, it squeezes more HCE out of the pulp prior to future bleach stages to increase their effectiveness and reduce subsequent bleaching chemical

requirements. Secondly in doing so, the pressing increases the solids concentration in the HCE by a measurable percentage that minimizes some of the water which must be removed in the evaporators. The new HCE washer will be needed at the 175,000 ADMT/yr production rate because the washer we are presently using as the third post HCE stage washer will be needed to maintain quality at the new rate in another stage in the bleach plant.

5. Provide a schedule and approximate dates for installation of the proposed improvements.
See page 8 of the attached Process Description. We expect to begin the work to get to 162,000 AMDT/yr immediately. The work to achieving 175,000 ADMT/yr will not begin until 2008. We have scheduled all of this work to begin at our normal shutdown period during the spring. The 2008 date is quite tentative. It is doubtful all projects would be completed that year. It is difficult to determine which we would start with.

6. Has the previous netting analysis changed as a result of the substituting evaporation for the membrane technology first proposed?
Fortunately the netting analysis has not changed. In the original analysis we had not taken a reduction in the HCE evaporation from switching to membrane technology. We increased all evaporator emissions by the production increases. Therefore, the netting analysis already included the new evaporation emissions. This is also explained in the additions to the revised Process Description attached.

7. What is the caustic chemical used in the HCE stage?
Sodium Hydroxide (NaOH).

Sincerely,

F. J. Perrett by CA. M-[illegible]

F. J. Perrett
General Manager

cc: Chris Kirts, DEP – NED
David Tudor, Contact, RPF
David A. Buff. P.E., GAI

Process Description

The Rayonier Fernandina Chemical Cellulose Sulfite Pulp Mill has been in operation at this site since 1939 and currently employs approximately 280 people. The mill uses a sulfite (ammonia-base) process to produce various grades of chemical cellulose from pine wood-chips. There are only two other pulp mills located in USA that produce products similar to the Fernandina Mill and neither of these mills use the same type of manufacturing process. This plant produces approximately 10 different grades of cellulose each with different specifications and customers. The amount of each grade of product that is produced is based on market demand. The cellulose produced at this mill goes into such products as plastics, photographic film, LCD screens, paints, cigarette filters, pharmaceuticals, food products, cosmetics and textiles. Customers of these products have stringent quality requirements. This mill produces approximately 150,000 tons of performance fibers annually.

The sulfite process utilizes a sulfurous acid and ammonium bisulfite cooking solution to chemically separate the lignin from the cellulose. This is accomplished in six batch pressure vessels called digesters. The "cooking" process requires approximately 6 hours. The pulp and spent cooking solution [SSL – spent sulfite liquor] are separated over vacuum washers called red stock washers. The pulp continues into the screening area while the SSL is pumped to the evaporators. The cooking solution is prepared in the "acid plant". All of the sulfur dioxide which is not captured in the acid making or emitted from the digestion and red stock washer processes is collected and scrubbed in the vent gas scrubber utilizing caustic soda. In this scrubbing tower is a second section for condensing a cooking process by-product, methanol. The methanol is condensed and sent to the effluent treatment system for biological digestion.

Unbleached sulfite pulp from the digesters has un-cooked woody materials called knots and tailings which must be screened from the pulp. Knotters and Cowan screens are utilized to remove these materials. The knots and tailings are collected and pressed for utilization as fuel in the power boilers.

Pulp exiting the screening operation enters the bleach plant. One bleaching stage is called Hot Caustic Extraction [HCE]. This is a batch stage utilizing caustic soda to remove small chain cellulose molecules called hemi-cellulose from the pulp. This process uses small pressure vessels called HCE cells. No sulfur compounds are used in this stage. A spent solution washed from the pulp after this stage is called hot caustic extract [HCE] and is sold to kraft mills for its sodium content and energy value. This stage also has methanol as a by product in the vent gas, but presently it is not captured.

Pulp leaving the hot caustic stage is further purified in continuous and batch stages using peroxide, chlorine dioxide, chlorine, sodium hydroxide, and sodium hypochlorite depending on the pulp grade specifications. Following these "bleaching" stages the pulp passes through centrifugal dirt cleaners on the way to the pulp machine. The pulp machine forms the sheet by draining water from pulp slurry containing 99% water over a moving wire to a consistency of 50% water. The remainder of the water is removed by passing the pulp sheet over pressing and drying cylinders heated internally with steam. The sheet is wound on a "jumbo" roll which when completed weighs over 10 tons. The final sheet only has about 7% moisture. No coating occurs on any of the grades produced.

The jumbo rolls are transported to the finishing room where the pulp sheet is cut into smaller rolls or sheets which fit the customers' processes. The finished rolls or bales are shipped to the customer based on their order. No pulp is produced without an order due to the very specific quality requirements and sheet size for each customer.

The digestion, hot caustic extraction stage and pulp machine are high users of steam for heating. The steam is produced in three 1939 vintage power boilers utilizing bark and number 6 oil for fuel. Steam is also used to produce about 90 percent of the mill's electricity needs. The boiler's emissions are cleaned with venturi-type scrubbers.

The spent sulfite liquor [SSL] from the digestion process and the hot caustic extract [HCE] are pumped to the evaporators. From the evaporators the SSL is burned in the recovery boiler. This 1976 boiler provides steam for the evaporators and its emissions are scrubbed for sulfur dioxide removal using an ammonia solution. The ammonium bisulfite produced in the scrubber is used for cooking acid make-up. The emissions are further cleaned with mist filters that remove the ammonium sulfate particulate formed in the scrubber. Methanol from the evaporator vents is piped to condensers which collect the methanol and send it to the biological treatment system.

Boiler Project Description

Rayonier is planning to replace three existing power boilers at its Fernandina Beach dissolving sulfite pulp mill with one bubbling bed boiler. Self produced bark will provide most of the fuel, but knots, landscape waste and possibly a small amount of tire derived fuel will be fired at times. Minimal oil will be fired, mostly during periods when the solid fuel feed system is down. The mill has three small power boilers, all were installed prior to 1962, Power Boiler No. 1 is fired with No. 6 fuel oil only and has a heat input of 185mmBtu/hr. Power Boiler No. 2 is fired with bark and No. 6 fuel oil and has a heat input of 218 mmBtu/hr. Power Boiler No. 3, Title V Emission Unit PB03, is fired with bark and No. 6 fuel oil and has a heat input of 245 mmBtu/hr. These boilers are aging and maintenance costs have escalated to the point where replacement is cost effective. They will be decommissioned and therefore the emissions from these boilers will be used to offset the emissions from the replacement boiler. The replacement boiler will be designated PB06.

A used traveling grate boiler will be purchased which will be converted into a bubbling bed boiler equipped with an electrostatic precipitator followed by an alkaline scrubber. Provisions will be made to install Selective Non-Catalytic Reduction ("SNCR") for NOX control should it be necessary to meet the emission limit proposed. A newer boiler will reduce most emissions because it will have to meet more stringent New Source Performance Standards ("NSPS"), (40 CFR Part 60 Subpart D) and the recently promulgated Maximum Available Control Technology Standards ("Boiler MACT", 40 CFR Part 63, Subpart DDDDD for existing power boilers). The boiler being purchased was originally constructed in 1983. A reconstruction analysis demonstrates this boiler has not been reconstructed. Therefore, it remains subject to the Subpart D standard, of Part 60. Not being reconstructed also means the boiler is regarded as an existing boiler under Boiler MACT.

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

It will be located adjacent to the digesters east of the mill. Once constructed and fully operational, it will be connected to the mill steam headers. It and the recovery boiler will be the sole steam producers used by the mill. Eventually the existing boilers will be dismantled.

A large electrostatic precipitator (ESP) for the removal of particulate matter followed by an alkali scrubber for the removal of SO_2 will be installed to enable the boiler to meet the new emission limits. The technology used in the boiler and its new large pollution control devices will enable compliance with the new regulations referenced above and will allow a greater percentage of bark and possibly other solid fuels such as Tire Derived Fuel (TDF) in the fuel mix. Continuous NO_x, SO_2, flow, CO, O_2 and opacity monitors are proposed for the new boiler.

Production Increase Project Description

This permit application also includes a production increase to accommodate the full production enabled by the installation of No. 6 digester in 1998. Rayonier undertook a program to entirely reline each of its existing 5 digesters with new refractory and replace any weakened or corroded metal while it was exposed. To accomplish this Rayonier rotated a digester out of production for an extended period of time. In order to avoid lost production for orders previously taken an additional (No. 6) digester was added. Permitting of No. 6 digester was facilitated by inclusion of a production limit on the Title V operating permit of 153,205 ADMT per year. This application revisits that production limit and seeks to increase that limit to the full production capability of No. 6 digester.

Jeff and Bruce, just replace the last page on what we originally sent with this to address the production increase projects.

Minimal additional equipment will be needed to achieve the 162,000 AMDT/yr production increase requested in this application. An increase in machine drying capacity will be required. This will be accomplished by upgrading the dryer can system over which the pulp passes to dry the pulp; including increasing the drying steam pressure inside the cans, installing a new headbox to increase the width of the pulp web across the machine and to improve machine sheet uniformity at higher machine speeds, and upgrading control and water addition systems. There are no emissions associated with machine operations because there is no coating and the pulp has been purified to the point there are no remaining organics to emit. Also, three new evaporator modules will be added to form a new evaporator train to thicken the additional HCE produced by the increase in production. These evaporators will be sufficient to handle all the additional HCE for the 175,000 ADMT/yr production rate when accompanied with HCE washer upgrades. Also to achieve this production rate the mill will add a post-HCE washer press roll. The press roll will result in higher pulp consistency from the washer and higher solids concentration in the HCE liquor from the washer to the evaporators. This merely increases the effectiveness of the HCE collection system. There are no emissions from the press roll as no chemical reactions are taking place; water is being removed from the pulp. The condensed water from these evaporators may be usable, if not it will go directly to the water treatment plant. The vapors that are not condensed will go first to the existing methanol scrubber. The condensed organics from this condenser will go to the wastewater treatment plant. Water9 was used to estimate the amount of VOCs stripped by the aerators. The emission estimates provided assumed no control from the HCE stage up to 162,000 ADMT. For 175,000 ADMT/yr the calculations assume the HCE blow heat recovery project is installed.

To achieve 175,000 ADMT/yr the mill will further increase the drying capacity of the machine by further increasing drying steam pressure. Other potential pulp machine upgrades that may be needed depending on the effectiveness of the initial improvements involve final-sheet cooling, Fourdrinier wire vacuum system improvements, ventilation system upgrades and drive system enhancements. This is all non-emitting equipment. A new HCE cell will be added to handle the increased volume of pulp at the 175,000 ADMT/yr rate. Emissions from this new cell as well as all the existing cells will be controlled using a blow heat recovery system that will be installed and operational before exceeding the 162,000 ADMT/yr rate. With the continuing trend toward higher purity pulp production an additional washer will likely be required for the caustic extraction stages to reach the 175,000 ADMT/yr rate. This washer would be after release and capture of VOCs from the HCE blow heat recovery system and would have no sulfur dioxide or chlorine emissions.

To ensure VOC emissions increases are less than the PSD Significance Level the mill will undertake a project to capture blow heat from one of the bleach plant stages that is the most significant VOC emissions source. The HCE blow heat capture system will be very similar to the systems used on Kraft digesters for the recovery of heat except it will be considerably smaller and there will be no TRS gases as there is no sulfur in the pulp at this stage. The blow gas will be condensed to extract the heat and the condensate will contain the VOCs from the emissions of all the HCE cells. This condensate will be sent to the biological wastewater treatment system where it will be biologically destroyed. The emissions from the HCE blow tank have been measured. The reduction in emissions that will be achieved has been calculated at greater than 74% control of HCE blow emissions. Other emissions around the bleach plant were increased proportional to the production increase. The reduction in VOC emissions achieved by the new more efficient boiler and the HCE blow heat recovery more than offset increases in VOCs due to the 162,000 or the 175,000 ADMT/year production levels. All other pollutants do not increase sufficiently to tripper PSD review. Based on AORs the emissions for pertinent segments of the mill have been quantified and increased proportional to the production increase. This emissions increase is presented in the table below. The only additional control included in this estimate is the reduction in VOC achieved by the HCE blow heat recovery.

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

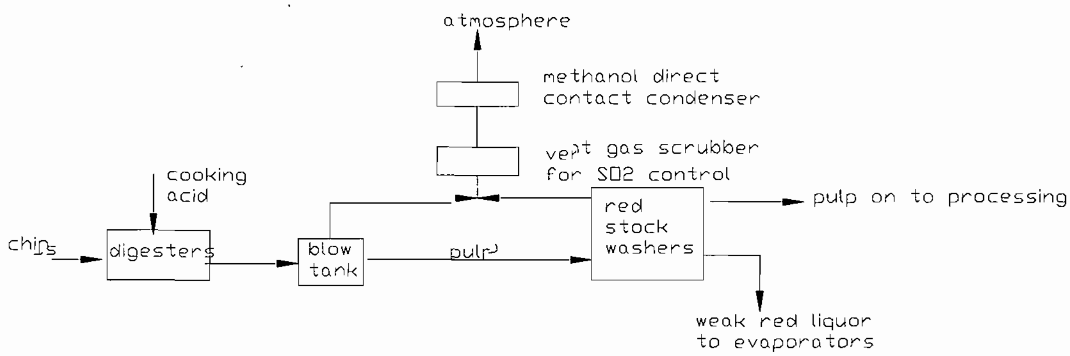
A tentative schedule for the various projects in the phased production increase is as follows:

Add new HCE washer press roll	Feb. 2006
First machine improvements to drying and headbox	Feb. 2007
Add new evaporator train	Feb. 2007
Install HCE Blow Heat Recovery	Feb. 2008
Add New HCE Cell	Feb. 2008
Install new HCE washer	Feb. 2008
Second machine drying and speed increase projects	Feb. 2008
Install new post HCE washer	Feb. 2008

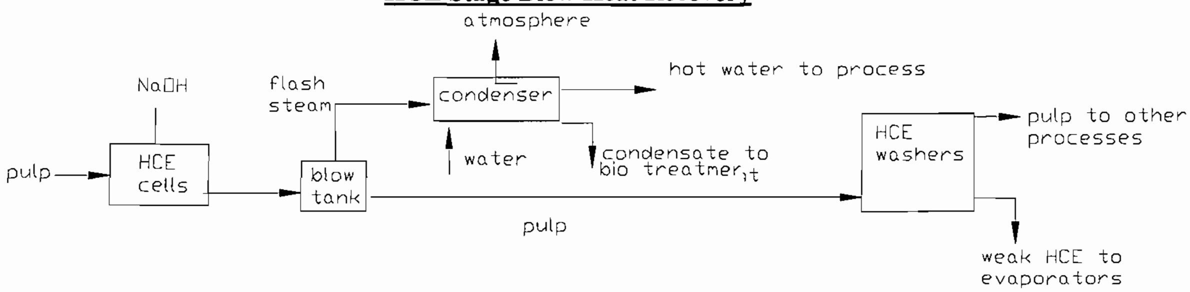
The original application included membrane technology to concentration the additional HCE. However, all of the baseline evaporator emissions were increased in the above table to estimate new emissions after production increases to 162,000 and 175,000. This assumes evaporation would be used to handle both the red liquor and the HCE. PSD permitting is not triggered even if all HCE produced at the 162,000 ADMT/yr rate were evaporated. At the 175,000 production rate, the 60% VOC collection efficiency used for the HCE blow heat recovery system is more than enough to offset any increase in evaporator emissions.

Flow sheet for Digester/Washer methanol control, HCE stage blow heat recovery, and evaporators.

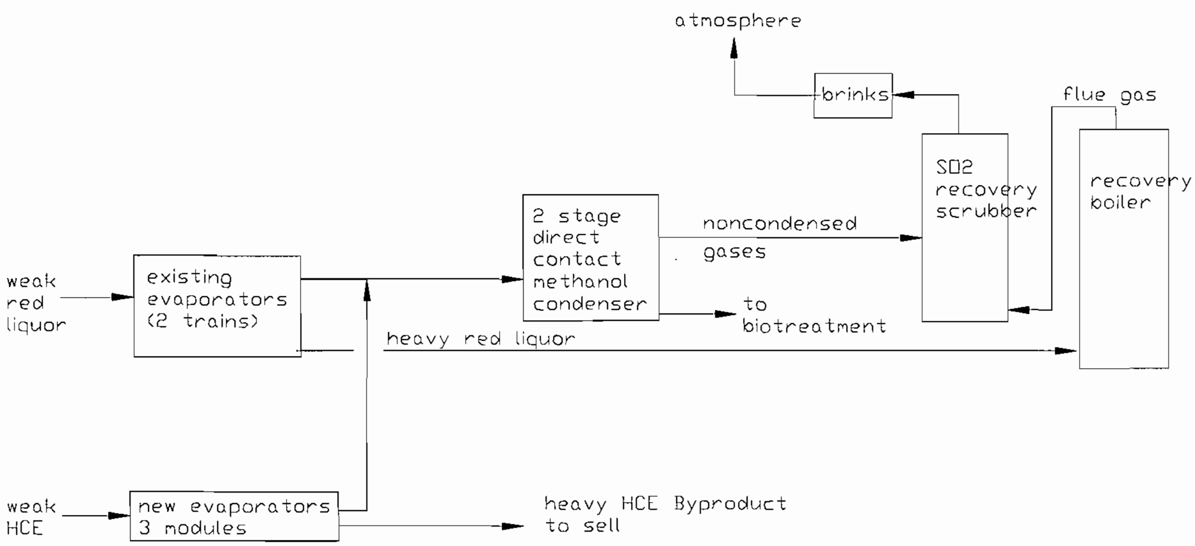
Flow sheet for Digester/Washer methanol control



HCE Stage Blow Heat Recovery



Evaporators



III. EMISSIONS UNIT INFORMATION - 021

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

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

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

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

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

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

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

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

Emissions Unit Description and Status

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

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

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

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

2. Description of Emissions Unit Addressed in this Section: **This emission unit comprises all evaporators. There are two existing evaporator trains. This construction permit adds one new train comprised of 3 evaporation bodies or modules which will be used to evaporate HCE.**

3. Emissions Unit Identification Number: **O21**

4. Emissions Unit Status Code: **A**	5. Commence Construction Date: **2/2006**	6. Initial Startup Date: **4/2007**	7. Emissions Unit Major Group SIC Code: **26**	8. Acid Rain Unit? [ ] Yes [X] No

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

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

11. Emissions Unit Comment:

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description:

This emission unit includes all evaporators. All evaporators vent through a common condenser used to collect methanol then vented to atmosphere via the sulfur dioxide recovery scrubber for the recovery boiler.

This application adds 3 evaporator modules or bodies to form a new evaporator train to be used to increase the solids concentration of weak HCE, a byproduct stream from the manufacturing process. HCE when thickened can be used by Kraft mills as a sodium source.

Vapors from the evaporators are sent to a two stage direct contact condenser. The condenser cools the evaporator emissions to remove methanol. The liquid from the condenser is sent to the biological waste water treatment plant where the methanol and any other captured VOCs are destroyed.

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

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

<u>Emissions Unit Operating Capacity and Schedule</u>

1.	Maximum Process or Throughput Rate:
2.	Maximum Production Rate: **237,922 unbleached air dried short ton**
3.	Maximum Heat Input Rate: million Btu/hr **NA**
4.	Maximum Incineration Rate: pounds/hr **NA** tons/day
5.	Requested Maximum Operating Schedule: **8** hours/day **7** days/week **52** weeks/year **8760** hours/year
6.	Operating Capacity/Schedule Comment:

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

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: **RB**	2. Emission Point Type Code: **3**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: **See Attachment 1 for Flow Sheet**	
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: **O21**	

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: **131,400** dscfm	12. Nonstack Emission Point Height: **NA** 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:	

D. SEGMENT (PROCESS/FUEL) INFORMATION

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

1. Segment Description (Process/Fuel Type): **This segment is the HCE evaporated by this two module evapoarator train.**		
2. Source Classification Code (SCC): **30700302**	3. SCC Units: **lb/Air Dried Short Ton Unbleached Pulp**	
4. Maximum Hourly Rate: **41.6**	5. Maximum Annual Rate: **267,922**	6.Estimated Annual Activity Factor: **NA**
7. Maximum % Sulfur: **NA**	8. Maximum % Ash: **NA**	9. Million Btu per SCC Unit: **NA**
10. Segment Comment: **175,000 ADMT/yr x 1.1023 ST/MT x 1.3889 UB/B = 267,922 ADSTUP (air dry short ton unbleached pulp)**		

Segment Description and Rate: Segment __ of __

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

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
VOC	099		EL

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –

POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control: **estimated 95%**
3.Potential Emissions: **14.10** lb/hour **61.78** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): **NA** to tons/year	
6. Emission Factor: **0.4612 lb VOC/ADUBST** Reference: **Emission Test results**	7. Emissions Method Code: **1**

8. Calculation of Emissions:

baseline production = 231,967 ADUBST
baseline emissions = 53.49 Ton/yr
emission factor = 0.4612 lb VOC/ADUBST
53.49 x 2000 lb/ton x 1/231967 ADUBST = 0.4612 lb VOC/ADUBST

New production = 267,922 ADUBST

New emissions = 267922 ADUBST/yr x 0.4612 lb VOC/ADUBST x 1 ton/2000 lbs
= 61.78 TPY x 2000 lb/T x 1yr/87860 hr = 14.10 lb/hr

9. Pollutant Potential/Estimated Fugitive Emissions Comment:

This emission estimate is for the entire emission unit which includes all evaporators.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -

ALLOWABLE EMISSIONS

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

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

1. Basis for Allowable Emissions Code:	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 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: **NA**	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:	
Visible Emissions Comment: **This emission exhausts to atmosphere through the recovery boiler stack.**	

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] of [1]

H. CONTINUOUS MONITOR INFORMATION

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

Continuous Monitoring System: Continuous Monitor 1 of 1

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

Continuous Monitoring System: Continuous Monitor ___ of ___

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

H. CONTINUOUS MONITOR INFORMATION (CONTINUED)

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

Continuous Monitoring System: Continuous Monitor ___ of ___

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

Continuous Monitoring System: Continuous Monitor ___ of ___

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

EMISSIONS UNIT INFORMATION
Section[1] of [1]

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

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

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

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

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

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

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

Additional Requirements for Air Construction Permit Applications

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

Additional Requirements for Title V Air Operation Permit Applications

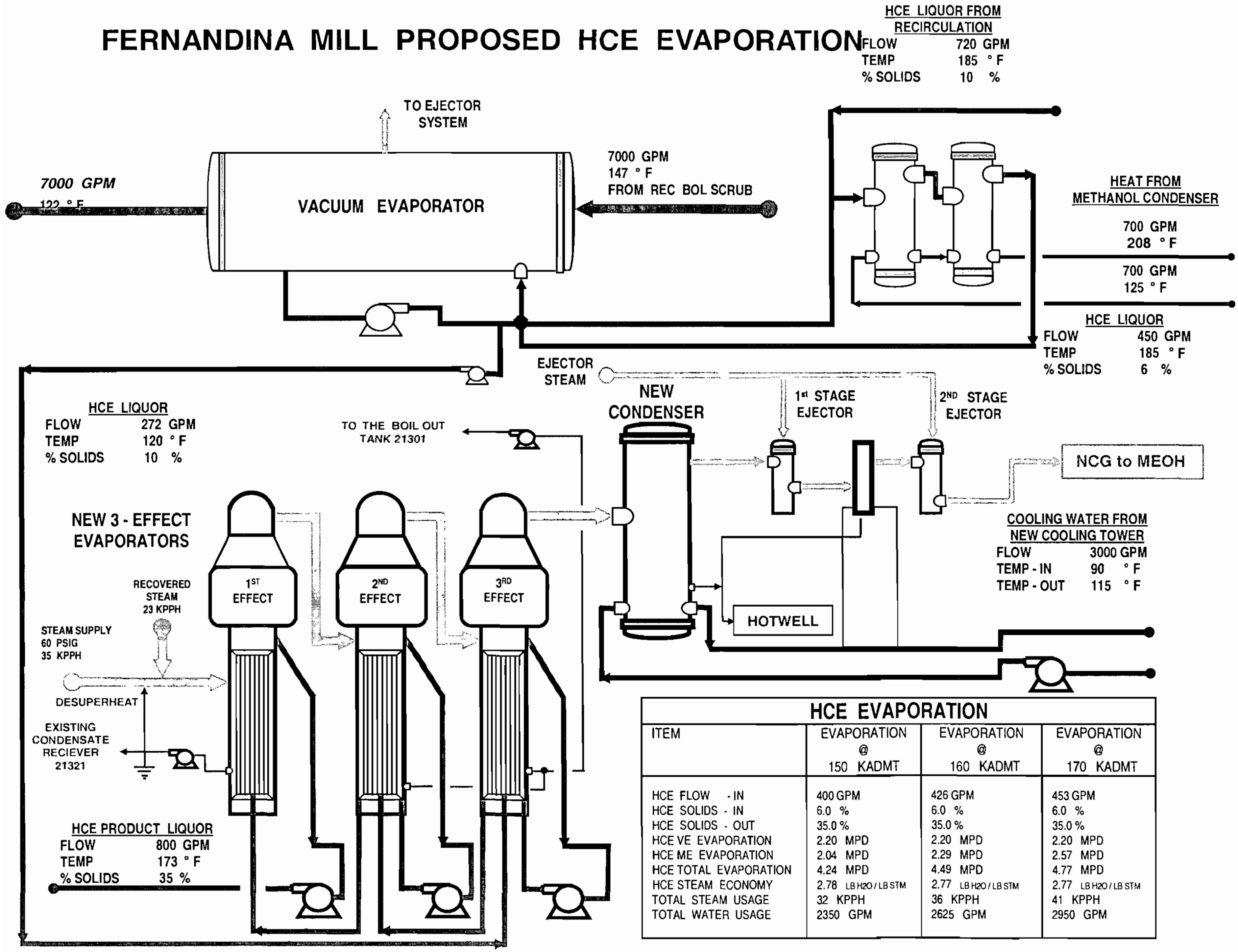
1. Identification of Applicable Requirements ☐ Attached, Document ID: _	
2. Compliance Assurance Monitoring ☐ Attached, Document ID: _	☒ Not Applicable
3. Alternative Methods of Operation ☐ Attached, Document ID: _	☒ Not Applicable
4. Alternative Modes of Operation (Emissions Trading) ☐ Attached, Document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

Additional Requirements Comment

Item 2 Fuel Analysis or Specification: is not applicable because this unit burns no fuel. Item 3 Detailed Description of Control Equipment is given in Emission Unit Control Equipment section.

ATTACHMENT 1

FERNANDINA MILL PROPOSED HCE EVAPORATION



HCE EVAPORATION

ITEM	EVAPORATION @ 150 KADMT	EVAPORATION @ 160 KADMT	EVAPORATION @ 170 KADMT
HCE FLOW - IN	400 GPM	426 GPM	453 GPM
HCE SOLIDS - IN	6.0 %	6.0 %	6.0 %
HCE SOLIDS - OUT	35.0 %	35.0 %	35.0 %
HCE VE EVAPORATION	2.20 MPD	2.20 MPD	2.20 MPD
HCE ME EVAPORATION	2.04 MPD	2.29 MPD	2.57 MPD
HCE TOTAL EVAPORATION	4.24 MPD	4.49 MPD	4.77 MPD
HCE STEAM ECONOMY	2.78 LB H2O / LB STM	2.77 LB H2O / LB STM	2.77 LB H2O / LB STM
TOTAL STEAM USAGE	32 KPPH	36 KPPH	41 KPPH
TOTAL WATER USAGE	2350 GPM	2625 GPM	2950 GPM

File Copy

Department of Environmental Protection

Jeb Bush
Governor

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

Colleen M. Castille
Secretary

January 18, 2006

CERTIFIED MAIL – Return Receipt Requested

Mr. F. J. Perrett
Environmental Manager
Rayonier Performance Fibers LLC
Fernandina Beach Mill
The Foot of Gum Street
P.O. Box 2002
Fernandina Beach, Florida 32035

RE: Request to Install the No. 6 Power Boiler and the No. 6 Batch Digester System
Air Construction Project No.: 0890004-018-AC

Dear Mr. Perrett:

On October 20, November 7 and December 19, 2005, the Department received responses to incompleteness letters regarding the above referenced project. Based on a telephone conversation with Mr. David Tudor, application contact, on January 18, 2006, and a review of the responses, we have determined that the application is still incomplete and the following additional information is needed in order to continue processing this application package. Please provide all assumptions, calculations, and reference material(s), that are used or reflected in any of your responses to the following issues:

1. Please provide an updated process flow diagram.

2. For the proposed new HCE evaporators, please complete the appropriate application pages and submit.

3. Based on today's conversation with Mr. Tudor, a correction was made regarding a proposed new ClO_2 "plant" versus a new ClO_2 "tower" (see page 24, Section 3.1 of the application package received September 12, 2005). If the ClO_2 plant is still desired, please complete the appropriate application pages and submit.

4. Please provide a description of the HCE evaporator project, including the pre-HCE thickener, the post HCE washer, etc.

5. Provide a schedule and approximate dates for the installation of proposed installations.

6. Based on all of the proposed changes at the facility, has the previously submitted "netting analysis" changed? If so, please describe, recalculate, and resubmit.

7. What is the caustic chemical that is being used in the HCE stage prior to bleaching?

The Department will resume processing this application after receipt of the requested information. If you have any questions regarding this matter, please call Bruce Mitchell at (850)413-9198.

Sincerely,

Jeffery J. Koerner

Jeffery F. Koerner, P.E.
Permitting North Administrator
Bureau of Air Regulation

JFK/bm

cc: Chris Kirts, DEP - NED
David Tudor, Contact, RPF
David A. Buff, P.E., GAI
Bruce
Jeff
Trina's file

"More Protection, Less Process"

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- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Mr. F. J. Perrett, Environmental Manager
Rayonier Performance Fibers LLC
Fernandina Beach Mill
The Foot of the Gum Tree
Post Office Box 2002
Fernandina Beach, FL 32035-2002

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X Claire Duke ☐ Agent ☐ Addressee

B. Received by (*Printed Name*) | C. Date of Delivery

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? *(Extra Fee)* ☐ Yes

2. Article Number
(Transfer from service label) 7000 1670 0013 3110 0154

PS Form 3811, February 2004 Domestic Return Receipt 102595-02-M-1540

U.S. Postal Service
CERTIFIED MAIL RECEIPT
(Domestic Mail Only; No Insurance Coverage Provided)

7000 1670 0013 3110 0154

Postage	$
Certified Fee	
Return Receipt Fee (Endorsement Required)	
Restricted Delivery Fee (Endorsement Required)	

Postmark
Here

Mr. F. J. Perrett, Environmental Manager
Rayonier Performance Fibers LLC
Fernandina Beach Mill
The Foot of the Gum Tree
Post Office Box 2002
Fernandina Beach, FL 32035-2002

PS Form 3800, May 2000 See Reverse for Instructions

Rayonier

Performance Fibers

Fernandina Mill

RECEIVED

DEC 19 2005

BUREAU OF AIR REGULATION

December 15, 2005

Jeffery F. Koerner
Bureau of Air Resources
2600 Blair Stone Road
Tallahassee, FL 32399-2400

RE: Application for Air Construction Permit
Project: Power Boiler Replacement and Digester Production Increase
Project No. 0890004-018-AC
Response to Request for Additional Information

Dear Mr. Koerner:

I am responding to your letter dated December 7, 2005 requesting additional information regarding the above referenced Application. I respond to your questions in the order presented in your December 7 letter.

1. You have requested that the projection of emissions be combined for both projects. The projected emissions changes from No. 6 boiler were presented in Table 10 on page 20 of the Narrative document that accompanied the application forms and the summary of emissions changes for No. 6 digester appeared in Table 13 on page 32. Below we have combined these two Tables.

Pollutant	Emission Change No. 6 PB Original Ton/Yr.	Emission Change No. 6 PB Adjusted Ton/Yr.	Emission Change No. 6 Digester Original Ton/Yr.	Emission Change No. 6 Digester Adjusted Ton/Yr.	Total Combined Emissions Change Ton/Yr.	PSD Significance Level Ton/Yr.
PM	(138)	(138)	NA	NA	(138)	25
PM10	(105)	(105)	NA	NA	(105)	15
SO_2	39	28.1	10.9	10.9	39	40
NO_x	39	39	NA	NA	39	40
CO	(591)	(591)	25.12	25.12	(565.88)	100
VOC	(45)	3.94	26.77	26.77	30.71	40

The baseline sulfur dioxide emissions from the old boilers is 181.96 tons/yr. which are used for netting plus the 39 tons/yr. available from the Significance level to avoid PSD permitting. Thus boiler emissions can increase from 181.96 to 220.96 tons/yr.

This 220.96 tons/yr. includes:
44.72 tons/yr. allowed from 11,925 thousand gallons annual No. 6 fuel oil usage,
10.90 tons/yr. from the 16.70 percent production increase; and
165.38 tons/yr. from TDF
220.96 total ton/yr. SO_2

Sulfur dioxide emissions from TDF are not required to be scrubbed as TDF is not oil. Thus the maximum SO_2 emissions allowed without triggering PSD is assigned to TDF. This does not change the annual average SO_2 emission rate of 0.1121 lb./mmBtu. This does require Rayonier to reduce the emissions from TDF by 63%. Since the SO_2 CAP does not change we have not resubmitted a revised section F1 for SO_2. We have submitted a Section F1 for VOCs reflecting the discussion below.

The carbon monoxide emission rate we used for the new boiler is based on the vendor guarantee of 0.25 lb. CO per mmBtu heat input. We used for estimation 0.3 lb./mmBtu.

The study provided by Babcock and Wilcox on the design for this boiler indicated VOC emissions of 0.002 lb. VOC/mmBtu. However, we estimated emissions from new No. 6 boiler based on an emission test from a similar boiler at Interstate Paper where VOC's were tested at 1.1 tons per year as carbon. This is an average of 3 one-hour test runs. This boiler is slightly smaller but similar to No. 6 and had an emission rate of 0.000837 lb./mmBtu. If the B and W study emission factor of 0.002 is used annual VOC emissions increase to 3.94 tons/year. If the test result of 0.000837 is used, the emissions increases would be 1.65 tons/year. Neither emission rate would cause emission increases to exceed the PSD Significant Levels.

There are two ways in which the Table above is conservative. First, we ignore the reduction in VOC from the shutdown of the old boilers. Also this analysis is completed for the 8% production increase because it will result in the maximum VOC increase. The 16% production increase includes the HCE blow gas heat recovery which accomplishes a large net VOC reduction overall.

We have also modified the Table to remove all of the VOC reductions previously taken. The VOC emissions used in the original application included emissions attributable to a waste caustic source from the bleach plant used as the scrubbing media, as well as the emissions from the older inefficient boilers. For cost and fresh water conservation reasons we still intend to use that caustic source as a scrubbing media. It is impossible to tell how much of the VOC's are attributable to the old boilers and how much to the waste caustic source. As a conservative approach to determining the VOC increases due to the boiler we just ignored possible decreases attributable to the old boilers and added the 3.94 tons/year attributable to the new boiler to the VOC's expected from No.6 digester without the reductions from the HCE blow heat recovery project. Even so, the total VOC emission increases are 30.71 tons/year or less than the PSD Significant Level. A Section F1 of the application form for VOCs is enclosed.

2. A partial response to this question is provided in the paragraph above. Attached are new pages to the application form providing VOC emission factors and rates using the 0.002 lb./mmBtu vendor study referenced above. We expect to stack test this boiler after it has started up and would have no objections to including VOC's in the suite of pollutants tested.

3. No. 6 boiler was originally permitted by Smurfit as a 540 mmBtu/hour boiler, 397 mmBtu/hour from coal and 143 mmBtu/hour from bark. On an annual basis, Rayonier will operate No.6 boiler at a heat input of 450 mmBtu/hour. However, since Rayonier is expecting to operate this boiler at 525 mmBtu/hr for limited periods of time when the recovery boiler is down this analysis is completed for that operating rate. A revised Table 3 is provided below with the emission rates of the two boilers presented in units of lbs./hour based on the permitted rates and heat input while Smurfit operated the boiler and the expected emission and heat input rates that Rayonier is permitting.

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

Pollutant	**Limit in Smurfit Permit** **Lbs./mmBtu unless indicated**	**Emissions from 540 mmBtu/hr Smurfit Boiler** **Lbs./hr unless indicated**	**Limit Expected for Rayonier No. 6 boiler** **Lb./mmBtu unless indicated**	**Emissions from 525 mmBtu/hr Rayonier No.6** **Lbs./hr unless indicated**
PM	0.1	54	0.07	36.8
Opacity	=20% except 6/hr<27%	NA	=20% except 6/hr<27%	NA
SO_2 solid fossil fuel	1.2	476.4	NA	NA
SO_2 liquid fossil fuel	0.8	NA	0.8	168.0
NO_x	0.3	162.0	0.1928	101.2

It is clear that the mass hourly emission rate does not increase and the boiler is not subject to Federal New Source Performance Standards.

If you have questions regarding this response please contact David Tudor at (904) 277-1452, cell (904) 557-8332 or e-mail: david.tudor@rayonier.com, or Dick Hopper at (904) 277-1480, e-mail: dick.hopper@rayonier.com.

Sincerely,

Jack Perrett

Jack Perrett
General Manager

cc: Bruce Mitchel
Chris Kirts

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control: **99.9% +**
3.Potential Emissions: **1.05** lb/hour **3.94** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): **NA** to tons/year	
6. Emission Factor: **0.002 lb/mmBtu** Reference: **Boiler Manufacturer Study**	7. Emissions Method Code: **5**
8. Calculation of Emissions: **hrly: 525 mmBtu/hr x 0.002 lb/mmBtu = 1.05 lbs/hr** **ann: 450 mmBtu/hr x 0.002 lb/mmBtu x 1/2000 tons/lbs x 8760 hr/year = 3.94 TPY**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -

ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions __ of __

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

Allowable Emissions Allowable Emissions __ of __

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

Allowable Emissions Allowable Emissions __ of __

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

Professional Engineer Certification

1. Professional Engineer Name: **David A. Buff**
   Registration Number: **19011**
2. Professional Engineer Mailing Address...
   Organization/Firm: **Golder Associates Inc.****
   Street Address: **6241 NW 23rd Street, Suite 500**
   City: **Gainesville** State: **FL** Zip Code: **32653-1500**
3. Professional Engineer Telephone Numbers...
   Telephone: **(352) 336-5600** ext.**545** Fax: **(352) 336-6603**
4. Professional Engineer Email Address: **dbuff@golder.com**
5. Professional Engineer Statement:

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

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

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

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

(4) If the purpose of this application is to obtain an air construction permit (check here ☒, 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
Signature

12/16/05
Date

(seal)

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

Jeb Bush
Governor

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

Colleen M. Castille
Secretary

December 7, 2005

CERTIFIED MAIL – Return Receipt Requested

Mr. F. J. Perrett, Environmental Manager
Rayonier Performance Fibers LLC
Fernandina Beach Mill
The Foot of Gum Street
P.O. Box 2002
Fernandina Beach, Florida 32035

RE: Application for Air Construction Permit
Project: Power Boiler Replacement and Digester Production Increase
Project No. 0890004-018-AC

Dear Mr. Perrett:

On October 20, 2005 and November 7, 2005, the Department received responses to an incompleteness letter regarding the above referenced project. Based on a review of the responses, we have determined that the application is still incomplete. In order to continue processing your application, the Department will need the additional information requested below. Should your response to any of the items below require new calculations, please submit the new calculations, assumptions, reference material and appropriate revised pages of the application form.

1. With regard to the recovery boiler and the production increase, your application appears to be based on the assertion that no physical or operational changes are being made to the unit, the unit can physically accommodate the increased production, and no changes to the existing permits are necessary to accommodate the increased production. In light of the Department's proposed New Source Review Reform regulations, the Department is considering the "demand growth" information presented in your letter dated November 7th. Nevertheless, the application does include a PSD netting analysis, which requires that all contemporaneous emissions increases and decreases at the plant be included. Therefore, any increases or decreases related to the digester production increase must be included in the overall PSD netting analysis. Revise the PSD netting analysis to include the digester production increase. Please verify the CO and VOC emission rates from Power Boiler No. 6 as reported in the netting table. Note that it may be necessary to make slight adjustments to the requested emissions limits for Power Boiler No. 6 for the project to remain minor with respect to PSD applicability.

2. As presented in Attachment 1 (Page 17 of 22) to your letter response dated October 12th, VOC emissions from Power Boiler 2 are based on an AP-42 emission factor of 0.038 lb/MMBtu of heat input from bark firing. The original application form (Section F1) did not address VOC emissions from proposed Power Boiler No. 6. Table 10 in the Attachment 5 to the original application suggests annual VOC emissions of 7.4 tons/year from Power Boiler No. 6. Please verify the VOC emissions factor and rates from each fuel for Power Boiler No. 6 and provide the corresponding application pages. The Department intends to require at least initial testing to determine VOC emissions from the new unit.

3. In your letter response dated October 12th, Table 3 in response #9 compares maximum emissions in terms of "lb/MMBtu" to determine whether or not Power Boiler No. 6 is a "modified" boiler subject to NSPS Subpart Db. This analysis requires a comparison of mass emission rates (lb/hour) for the determination. Please identify the maximum heat input rates for the *original* Power Boiler No. 6 and update Table 3 based on mass emission rates (lb/hour). Will the proposed conversion of this boiler result in increased mass emission rates of any regulated pollutant and trigger NSPS Subpart Db requirements?

The Department will resume processing your application after receipt of the requested information. Rule 62-4.050(3), F.A.C. requires that all applications for a Department permit must be certified by a professional engineer registered in the

State of Florida. This requirement also applies to responses to Department requests for additional information of an engineering nature. For any material changes to the application, please include a new certification statement by the authorized representative or responsible official. You are reminded that Rule 62-4.055(1), F.A.C. requires applicants to respond to requests for information within 90 days or provide a written request for an additional period of time to submit the information.

If you have any questions regarding this matter, please call me at 850/921-9536.

Sincerely,

Jeffery F. Koerner, P.E.
BAR - Air Permitting North

cc: Mr. Chris Kirts, NED
Mr. David Tudor, Rayonier Performance Fibers LLC
Mr. David A. Buff, Golder Associates Inc.

SENDER: *COMPLETE THIS SECTION*

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Mr. F. J. Perrett, Environmental Manager
Rayonier Performance Fibers LLC
Fernandina Beach Mill
The Foot of the Gum Tree
Post Office Box 2002
Fernandina Beach, FL 32035-2002

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X Theresa Mason ☐ Agent ☐ Addressee

B. Received by (*Printed Name*) Theresa Mason

C. Date of Delivery 12/3

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

2002

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? (*Extra Fee*) ☐ Yes

2. Article Number
(*Transfer from service label*) 7001 0320 0001 3692 3999

PS Form 3811, February 2004 Domestic Return Receipt 102595-02-M-1540

U.S. Postal Service
CERTIFIED MAIL RECEIPT
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7001 0320 0001 3692 3999

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Certified Fee		
Return Receipt Fee (Endorsement Required)		
Restricted Delivery Fee (Endorsement Required)		

Mr. F. J. Perrett, Environmental Manager
Rayonier Performance Fibers LLC
Fernandina Beach Mill
The Foot of the Gum Tree
Post Office Box 2002
Fernandina Beach, FL 32035-2002

PS Form 3800, January 2001 See Reverse for Instructions

Mitchell, Bruce

From: Koerner, Jeff
Sent: Wednesday, November 09, 2005 1:07 PM
To: Adams, Patty
Cc: Vielhauer, Trina; Mitchell, Bruce
Subject: RE: Rayonier

Patty,

Yes, I believe it does. The primary focus of their meeting with us yesterday was to convey the information provided in the November 7th letter regarding demand growth.

Thanks!

Jeff

From: Adams, Patty
Sent: Wednesday, November 09, 2005 12:12 PM
To: Koerner, Jeff
Subject: Rayonier

Jeff,

Does Rayonier's Nov. 7 letter reset the completeness review clock in ARMS? There's a couple of weeks left from the Oct. 24 response.

Patty

Mitchell, Bruce

From: Koerner, Jeff
Sent: Wednesday, November 09, 2005 1:57 PM
To: Mitchell, Bruce
Subject: Rayonier

Bruce,

I asked Patty to update ARMS for the Rayonier information we received. Since they have been sending documents every week, please check ARMS to see if it agrees with your record.

Thanks!

Jeff

I believe resetting the clock is appropriate due to the relevancy of the document. Bruce

Rayonier

Performance Fibers

Fernandina Mill

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November 7, 2005

Certified Mail, Return Receipt Requested

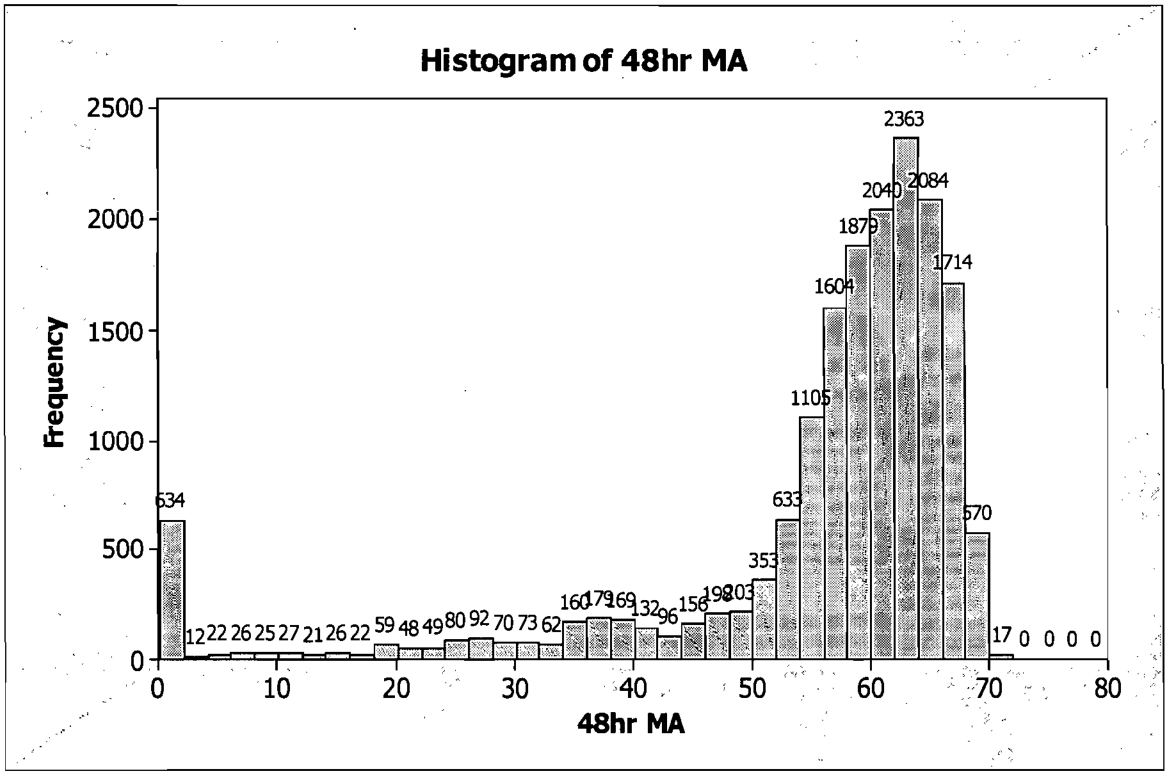
Mr. Jeffery F. Koerner, P. E.
Bureau of Air Regulation
Division of Air Resources Management
2600 Blair Stone Road, MS 5505
Tallahassee, FL 32399-2400

RE: Request to Install No. 6 Power Boiler, and the No.6 Batch Digester system
0890004-018-AC

Dear Mr. Koerner:

On October 20, 2005 Rayonier responded to your October 12, 2005 Request for Additional Information regarding the above referenced construction application. As discussed in greater detail in our recent correspondence, the emission analysis in the application excludes emissions that are not a "result" of the proposed change. This requirement that there be a causal connection between the proposed change and the emissions increase is recognized in the "Demand Growth" exclusion contained in the December 31, 2002 federal amendments. Because this clarification was judicially upheld by the United States Court of Appeals for the District of Columbia in State of New York et. al. vs U.S. Environmental Protection Agency ("Decision") and must be included in the Florida rules by the end of the year, we are providing you with supplemental information.

First, we provided the results of many tests showing the boiler could operate at the permit limit of 70,000 lbs of spent sulfite liquor ("SSL") solids per hour. In addition to these tests results, we are supplying information to demonstrate this boiler has repeatedly operated at the 70,000 lbs/hr rate during the baseline year period. The operating history shows a significant proportion of time the recovery boiler operates at or near 70,000 lb/hr rate. The histogram of 48 hour moving averages shown below demonstrates that for 570 periods in the 2003-2004 baseline period the boiler had an average burning rate of 68,000 lbs/hr. Hourly and daily histograms show even greater frequency of operation at the 70,000 lbs/hr rate.



Second, pursuant to the regulation, as upheld in the Decision, the demand growth emissions must be quantified and provided. We have used two methods to quantify these emissions. As you can see from the two tables below the two methods agree fairly well.

We first calculated demand growth emissions using the recovery boiler emissions used to calculate the 2003 and 2004 AORs and proportioning up just these emissions based on SSL burned. The table below gives these demand growth emissions.

SSL burned 2003	236,285	tons
SSL burned 2004	241,514	tons
Baseline SSL burning rate	238,900	tons
SSL burning rate at 70,000 lb/hr 8760 hrs/yr	306,600	tons
ratio increase in SSL burning	1.283	ratio

Parameter	baseline from 03/04 AOR	New Actual Emissions	Increase
CO	346.04	444.10	98.06
NOx	976.6	1,253.35	276.75
SO2	836.12	1,073.06	236.94
VOC	0.26	0.33	0.07
PM	67	85.99	18.99
PM10	68.6	88.04	19.44

We also recalculated these emissions based on SSL solids, but the procedure used involved the relationship between the liquor burning rate and the gas volume produced. Two pieces of data were utilized to define this relationship: The boiler design conditions as listed in the Title V permit application and actual emissions test of gas volumes for 2003-2005. The factor developed is 1.8 dscfm/(lb SSLS/hr). Utilizing this factor and the actual burn rates for the present operations [2004 data] the flue gas volume was determined. This volume was used with the average emissions concentrations for CO, NOx and SO2. The resultant ton/yr emission rate values were different [less] than reported in the 2004 AOR, but more accurate. Using the same procedure the emissions at the boiler permit limit capacity were determined and compared to the corrected 2004 emissions.

For VOC, the calculation involves the conversion of the boiler's permit limit liquor burning capacity to dry unbleached pulp production [ODUBT/yr]. Then the actual methanol testing values in lb/ODUBT were used to determine the permit limit capacity emission of VOC. For PM and PM10 a direct ratio of annual average liquor burn rate to the 70,000 lb SSLS/hr rate was used to determine the permit limit emissions rate.

2004	Emissions Ton/yr					
Parameter	AOR Oil Fired	AOR SSLS Fired	AOR Total	Corrected Total	70,000 lb SSLS/hr Emissions	Potential Increase
CO	5.29	410.58	415.87	373.98	437.50	63.52
NOx	49.72	2070.36	2120.08	1,906.62	2,230.45	323.83
SO2	6.91	789.75	796.66	714.54	858.28	143.74
VOC	0.80	34.90	35.70	[illegible]	38.78	3.08
PM	1.80	84.11	85.91	[illegible]	113.61	27.70
PM10	1.55	75.10	76.65	[illegible]	101.38	24.73

Furthermore, if there is a reasonable possibility that the project will result in a significant emissions increase, emissions must be monitored and recorded for a specified period of time (generally 10 years) to prove there has been no increase other than that allowed by demand growth.

In this case, the demand growth excluded emissions are recovery boiler emissions up to the existing permit limit. Tracking these emissions will be accomplished by tracking the amount of SSL solids burned and to ensure we do not exceed the 70,000 lb/hr annual average.

Though the Request for Further Information did not specifically ask for these emissions to be quantified, and the original application provided sufficient information to calculate them, by the first method above, we are providing this information given the likelihood of near-term regulatory changes to formalize the Demand Growth exclusion as mandated by EPA regulations and the Decision. We provide them here, prior to our November 8 meeting, should you have questions regarding the calculation. If you have questions before or after our November 8 meeting, you can contact David Tudor at (904)557-8332, david.tudor@rayonier.com, or Dick Hopper at (904)277-1480, dick.hopper@rayonier.com.

Sincerely,

F. Jack Perrett by CA McDonald

Jack Perrett
General Manager

CC: Bruce Mitchell
Trina Vielhaeuer

Rayonier

Performance Fibers

Fernandina Mill

November 2, 2005

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BUREAU OF AIR REGULATION

Certified Mail, Return Receipt Requested

Mr. Jeffery F. Koerner, P.E.
Bureau of Air Regulation
Division of Air Resources Management
2600 Blair Stone Road, MS 5505
Tallahassee, FL 32399-2400

RE: October 12, 2005 completed letter Response regarding Request to Install No. 6 Power Boiler, and the No. 6 Batch Digester system
0890004-018-AC

Dear Mr. Koerner:

As noted in Rayonier's October 20, 2005 response, issue 7, page 9, the reports for the 2004 and 2005 NOx tests were to be attached. At the time of the submission the formal report for the 2005 nitrogen oxides emissions test was not available, therefore only three reports were provided. This report has now been received from our emissions testing contractor and is attached for your review.

If there are any questions, please contact me at (904) 277-1480.

Yours very truly,

Richard Hopper

Richard W. Hopper
Manager, Environmental Operations

cc: Christopher Kirts – FDEP
Trina Veilhauer – DARM
JFP, DET

NITROGEN OXIDES EMISSIONS TEST REPORT
FOR
SULFITE RECOVERY BOILER AND SCRUBBER B
AT
RAYONIER
FERNANDINA BEACH, FLORIDA

Prepared for:

RAYONIER
P.O. Box 2002
Foot of Gum Street
Fernandina Beach, Florida 32034

Prepared by:

Source Testing And Consulting Services, Inc.
1100 Purple Glory Drive
Apex, North Carolina 27502

October 2005

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Table

1.0 INTRODUCTION

1.0 INTRODUCTION

Under contract to Rayonier, Source Testing and Consulting Services, Inc. (STACS) performed a series of emission tests at Rayonier's Fernandina Beach, Florida facility during 2005.

Emission testing was performed for the Sulfite Recovery Boiler and Scrubber B. The purpose of the tests was to provide gaseous emissions data for the units. This document presents the results from the gaseous emissions testing for nitrogen oxides (NO_x).

All testing followed the procedures and quality control guidelines as prescribed in EPA Methods 3A, and 7E of (40 CFR Pt 60, Appendix A). Testing at the Sulfite Recovery Boiler occurred on June 8, 2005. The gaseous tests at Scrubber B occurred on July 8 and July 14, 2005.

The test methods that were used for this test program are listed briefly below:

EPA Method 3A:	Continuous determination of oxygen and/or carbon dioxide content in the flue gas. A paramagnetic analyzer is used for O_2 determination for this test program.
EPA Method 7E:	Determination of nitrogen oxides using continuous emissions monitoring techniques with a chemiluminescent analyzer (RATAS).

All procedures and quality control guidelines specified in the appropriate methods, including 40CFR60 Appendix A, and in the EPA Quality Assurance Handbook for Air Pollution Measurement Systems - Volume III were strictly followed during the test program, in addition to STACS' more stringent internal quality control standards.

Section 2.0 of this report provides a brief process description and a diagram of the sample point locations. Section 3.0 presents the test results. Section 4.0 outlines the procedures and test methods used and Section 5.0 discusses the quality assurance/quality control measures followed during sampling and analysis. Field data sheets, laboratory data, sample calculations, calibration data, process data, and a list of project participants are included in the Appendices to this report.

2.0 PROCESS DESCRIPTION AND SAMPLE POINT LOCATIONS

2.1 SULFITE RECOVERY BOILER

2.1.1 PROCESS DESCRIPTION

The Sulfite Recovery Boiler produces steam by the combustion of spent sulfite liquor (SSL). Emissions from the unit are controlled by venting the effluent gases through a Katzen wet scrubber followed by venting the effluent gases through a series of Brinks mist filters.

2.1.2 REFERENCE METHOD SAMPLING LOCATION

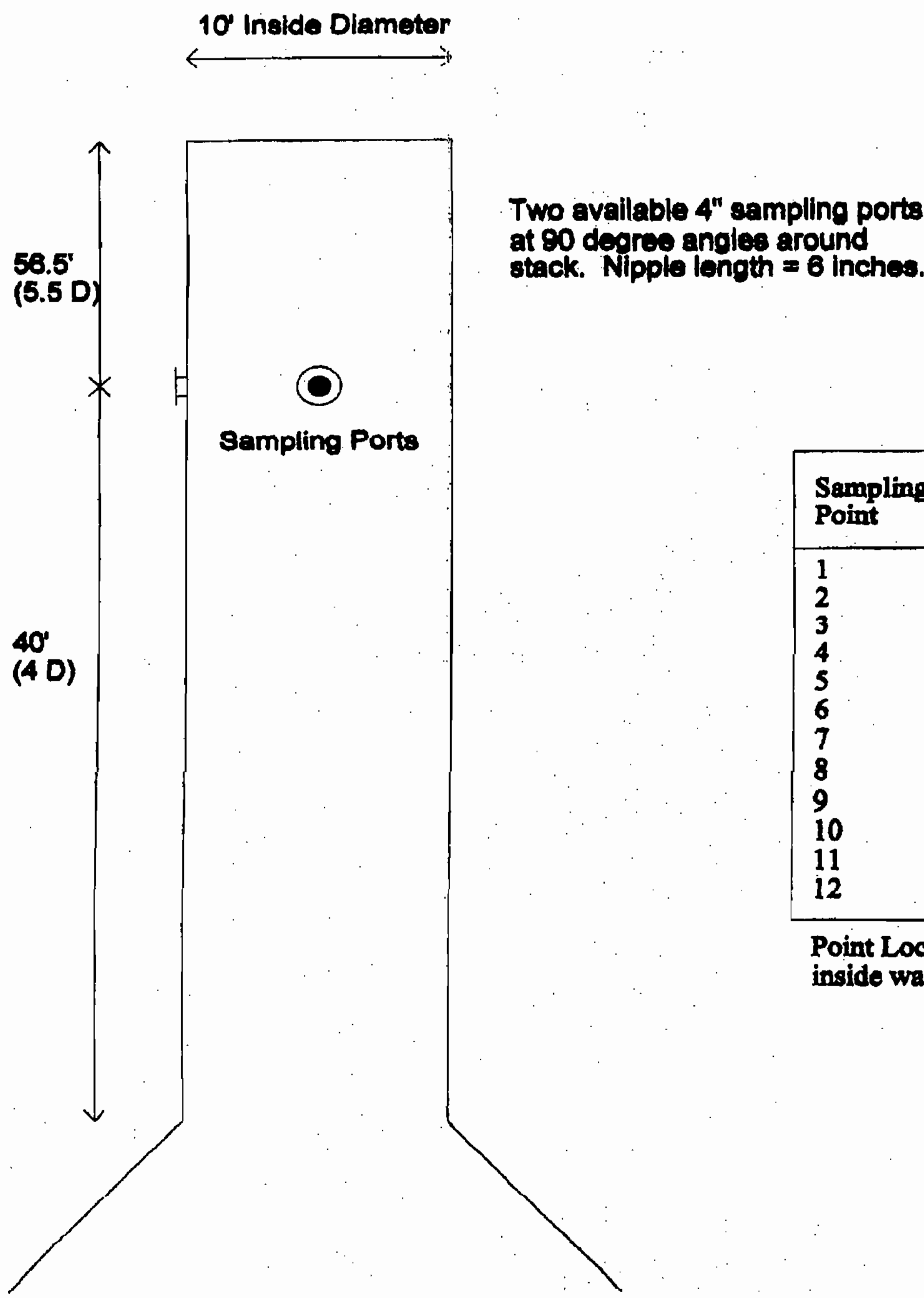
The reference method sampling port was located in the vicinity of the CEMs Probe in the exhaust ductwork from the unit. The ductwork is circular. Three sampling points were used for sampling the duct for each run and were located as described in PS2 Section 3.2 (40 CFR 60, Appendix B). The location is not required to meet EPA Method 1 criteria for the test methods used. A schematic diagram typical of the stack sampling location is included in Figure 2-2.

2.2 SCRUBBER B

The combined emissions from Boilers 2 and 3 are controlled by Scrubber B. Boiler 2 is fired with bark and Boiler 3 is fired with bark and/or oil.

2.2.1 PROCESS DESCRIPTION AND SAMPLING LOCATION

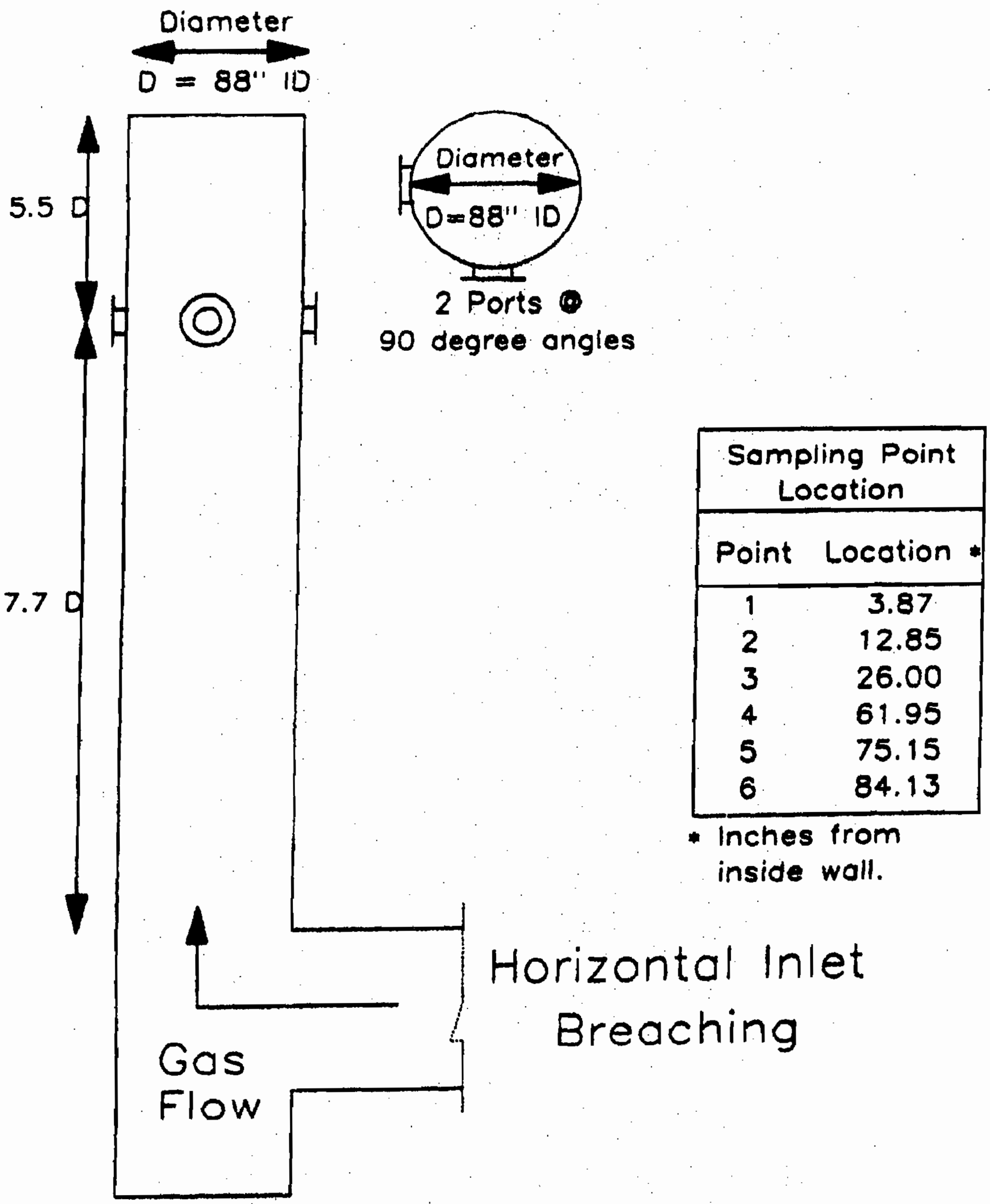
Gaseous and particulate matter emissions from scrubber B are controlled by venturi type scrubbers with entrained water demisters downstream of the venturi. The scrubber stack is 10' in inside diameter and was sampled through two ports 90° apart around the circumference of the stack. The nearest downstream disturbance from the sampling location was the atmospheric exhaust which was located one duct diameter away from the test ports. The nearest upstream disturbance was the top of the scrubber which was four diameters away from the ports. Three sampling points were used for sampling the duct for each run and were located as described in PS2 Section 3.2 (40 CFR 60, Appendix B). A schematic diagram typical of the stack sampling location is included in Figure 2-1.



Sampling Point	Point Location
1	2.52
2	8.04
3	14.20
4	21.24
5	30.00
6	42.70
7	77.30
8	90.00
9	98.80
10	105.80
11	111.96
12	117.48

Point Locations are inches from inside wall.

Figure 2-1. A & B Scrubber Stack Schematic Diagram



Sampling Point Location

Point	Location *
1	3.87
2	12.85
3	26.00
4	61.95
5	75.15
6	84.13

* Inches from inside wall.

Figure 2-2. Sulfite Recovery Boiler Stack Schematic Diagram

3.0 EMISSION TEST RESULTS

3.0 EMISSION TEST RESULTS

Testing for gaseous emissions was conducted for the Rayonier's Sulfite Recovery Boiler on June 8, 2005. Gaseous tests for Scrubber B were conducted on July 8 and July 14, 2005. The tests at Scrubber B included operations with bark only as the fuel and a combination of bark and oil. NOx emissions are presented as parts per million volume on a dry basis (ppmV, d). Oxygen (O2) is presented on a percent by volume dry basis. NO_x emission rates are provided in lb/hr. The raw reference data collected during the tests is included in Appendix A. Calibration, bias/drift calculations, and cylinder certificates are found in Appendix B.

Three points were traversed for the reference method sampling during each test. Three one hour test runs were conducted using the procedures outlined in EPA Methods 3A, and 7E. The sampling occurred while the units were at prescribed testing conditions for each test run.

3.1 SULFITE RECOVERY BOILER TEST RESULTS

The gaseous emission testing for the sulfite recovery boiler occurred on June 8, 2005. Testing was concurrent with the SO2 RATA tests. The boiler process data will therefore be the same as that data presented for the particulate and RATA tests. The results of the gaseous emissions tests are presented in Table 3-1.

3.2 SCRUBBER B TEST RESULTS

The gaseous emissions testing for Scrubber B occurred on July 8 and 14, 2005. Testing was conducted with and without supplemental oil firing with Unit 3 in operation emitting through Scrubber B on July 8. The tests on July 14 were performed with a combination of bark and oil fuel with only Unit 3 in operation. The boiler process data are included in Appendix D. The results of the gaseous emissions tests are presented in Tables 3-2 and 3-3.

Table 3-1. Sulfite Recovery Boiler Test Results, June 8, 2005

Date	6/8/05	6/8/05	6/8/05	
Start	9:00	10:54	12:53	
Stop	10:41	12:21	14:31	
Run	1	2	3	AVERAGE
Enission Parameter				
Volumetric Flow Rate, dscfm	110,182	119,105	119,731	116,339
O2 (%V,dry)	4.5	4.1	4.9	4.5
NOx (ppmV,dry)	590.3	576.2	637.3	601.3
NOx (@ 7% O2)	500.3	476.7	553.7	510.2
NOx, lb/hr	465.9	491.7	546.6	501.4

Note: Volumetric flow rate from concurent particulate matter tests that have been reported separately.

Reference: Source Testing and Consulting, Inc. 2005

Table 3-2. Scrubber B Test Results, July 8, 2005

Bark Fuel Only, Boilers 2 and 3 On							
Date	7/8/05		7/8/05		7/8/05		
Start	8:59		10:22		11:38		
Stop	9:59		11:22		12:38		
Run	1		2		3		AVERAGE
Operating Mode							
Boiler No.	2	3	2	3	2	3	
On/Off	On	On	On	On	On	On	
Bark Feed Rate, tons/hr	33.2		36.5		34.8		34.8
Oil Feed Rate, gal/hr	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Bark Heat Input Rate, million Btu/hr	216.6		213.8		222.6		217.7
Oil Heat Input Rate, million Btu/hr	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Heat Input, million Btu/hr	216.6		213.8		222.6		217.7
Enission Parameter							
O2 (%V,dry)	12.2		12.6		12.4		12.4
NOx (ppmV,dry)	56.7		51.2		52.6		53.5
NOx (@3%O2)	116.7		110.5		110.7		112.6
NOx (lb/MMBtu)	0.156		0.148		0.148		0.151
NOx, lb/hr	33.8		31.7		33.7		33.1

Bark and Oil Fuel, Boilers 2 and 3 On							
Date	7/8/05		7/8/05				
Start	13:58		15:08				
Stop	14:58		16:08				
Run	1		2				AVERAGE
Operating Mode							
Boiler No.	2	3	2	3			
On/Off	On	On	On	On			
Bark Feed Rate, tons/hr	22.7		22.6				22.7
Oil Feed Rate, gal/hr	0.0	785.4	0.0	792.6			789.0
Bark Heat Input Rate, million Btu/hr	130.6		135.9				133.3
Oil Heat Input Rate, million Btu/hr	0.0	124.0	0.0	125.0			124.5
Total Heat Input, million Btu/hr	254.6		260.9				257.8
Enission Parameter							
O2 (%V,dry)	12.0		12.0				12.0
NOx (ppmV,dry)	64.9		65.0				65.0
NOx (@3%O2)	130.5		130.7				130.6
NOx (lb/MMBtu)	0.171		0.171				0.171
NOx, lb/hr	43.5		44.7				44.1

Reference: Source Testing and Consulting, Inc. 2005

Table 3-3. Scrubber B Test Results, July 14, 2005

Bark and Oil Fuel, Boiler 2 Off, Boiler 3 On							
Date	7/14/05		7/14/05		7/14/05		
Start	9:01		10:18		11:38		
Stop	10:01		11:19		12:39		
Run	1		2		3		AVERAGE
Operating Mode							
Boiler No.	2	3	2	3	2	3	
On/Off	Off	On	Off	On	Off	On	
Bark Feed Rate, tons/hr	13.1		12.8		10.8		12.2
Oil Feed Rate, gal/hr	0.0	894.6	0.0	904.7	0.0	921.2	906.9
Bark Heat Input Rate, million Btu/hr	90.3		75.6		88.2		84.7
Oil Heat Input Rate, million Btu/hr	0.0	145.9	0.0	147.6	0.0	150.3	147.9
Total Heat Input, million Btu/hr	236.2		223.2		238.5		232.6
Enission Parameter							
O2 (%V,dry)	12.6		13.2		12.4		12.7
NOx (ppmV,dry)	73.2		69.8		72.0		71.7
NOx (@3%O2)	157.9		162.3		151.6		157.3
NOx (lb/MMBtu)	0.206		0.211		0.197		0.205
NOx, lb/hr	48.6		47.1		47.1		47.6

Reference: Source Testing and Consulting, Inc. 2005

4.0 FIELD AND ANALYTICAL PROCEDURES

4.0 FIELD AND ANALYTICAL PROCEDURES

4.1 INSTRUMENTAL REFERENCE METHODS

Stack gas emissions of oxides of nitrogen (NO_X) were measured using continuous instrumental techniques. Diluent oxygen concentration was also measured using continuous instrumental techniques. These tests are performed in accordance with EPA Methods 3A for oxygen and 7E for NO_X as outlined in Title 40, Part 60, Appendix A of the Code of Federal Regulations. Copies of all on-line instrumental reference method data collected during the testing are included in the Appendices to this report. Calibration records are also given with the data.

Flue gas sample is withdrawn from the stack at a constant rate via a heated stainless steel sample probe. The sample probe is equipped with an additional stainless steel line to enable probe tip calibrations. The probe is of sufficient length to allow traversing across the duct as required by the performance specifications and the applicable test methods. Extracted sample is passed from the probe through a filter and a heated teflon sample line to the moisture removal system. The moisture removal system (gas conditioner) is designed for minimal contact between condensate and sample gas in order to prevent any reaction between the moisture and the measured pollutants. All components of the sampling and gas conditioning system are fabricated from borosilicate glass, teflon, or stainless steel. The gas conditioning system consists of a continuously downward teflon condenser coil (to prevent bubbling) and two glass knockout condenser traps. Moisture is continuously removed from the traps by an external peristaltic pump. The gas conditioning system is cooled in an ice water bath to facilitate complete moisture removal. Dry gas sample from the gas conditioner is transported to the instrument enclosure via an unheated 1/4-inch O.D. teflon tube to a teflon-lined diaphragm pump, which delivers positive pressure sample to the instrument system. Flow control valves are used to deliver the gas sample at a regulated positive pressure to the reference method analytical instruments through a teflon and stainless steel manifold delivery network.

Flow and pressure to all monitors is held constant by monitoring sample and bypass rotameters. A diagram of the instrumental reference method sampling and analysis system used for the test program is given in Figure 4-1.

The sampling system is leak checked by passing known calibration gas standards up through a calibration line to the end of the probe. The gas standards are then pulled back through the sampling probe at stack pressure and subsequently through the entire sampling system to the instrument system. An oxygen analyzer response of less than or equal to 0.5% V to a zero oxygen standard is considered an acceptable leak check.

Analyzer calibration error is calculated by the difference between the known calibration gas concentration and the concentration exhibited by the analyzer. Bias checks are performed by comparing calibration responses through the entire sampling system to these exhibited at the analyzer. EPA Protocol #1, NIST traceable standard calibration gases are used to calibrate the analyzers.

Acceptable system performance checks do not exceed +/-2% calibration error, +/-5% system bias check, +/-3% zero drift, and +/- 3% upscale span drift.

Instrument response time is found by alternating zero nitrogen and upscale span gases through the bias check line and recording the upscale and down scale time. The response time of the CEM sampling system is performed to determine the length of time for the CEMs to respond to changes in the stack gas exhaust stream. Known, Protocol 1 reference gases and zero nitrogen are passed through the heated sample line, sample conditioning system and the manifold delivery network to the continuous emission monitors.

4.2 DATA ACQUISITION

The STACS data acquisition system (DAS) for the CEM analyzers consists of a Microlink 751 USB Data Interface and a proprietary STACS Data Acquisition program. The data are stored on disk as well as on a printed hard copy for each run. The system has 16-bit analog to digital conversion resolution (1 in 64,000) and a scan rate of approximately 1200 readings per minute. Data is averaged and reported by the DAS on a 30 second basis. The averaging time may be changed if desired. The system is capable of displaying the on line results in measured units and corrected to 15% O_2 as well as in lb/MMBtu. Averages are generated immediately at the end of each test run.

4.3 REFERENCE METHOD ANALYZER PRINCIPLES OF OPERATION

4.3.1 METHOD 3A: OXYGEN ANALYSIS

Flue gas sample is continuously analyzed for oxygen by a Servomex Model 1400A paramagnetic instrument. The Servomex 1400A analyzer uses electron paramagnetic resonance to detect the presence of oxygen molecules. Unlike most substances, oxygen has a triplet electron ground state, which leaves one electron unpaired, making it a paramagnetic molecule. This electron may have one of two quantum spin states (m_s = +/- 2). By applying an alternating electromagnetic field of the proper frequency, the Servomex 1400A O_2 analyzer induces resonance between the two spin quantum states. In effect, the O_2 analyzer measures the electromagnetic energy absorbed by O_2 molecules at the resonant frequency.

4.3.2 METHOD 7E: OXIDES OF NITROGEN ANALYSIS

A Thermo Electron Model 10S instrument is used to analyze NO_X. The principle of operation of this instrument is a chemiluminescent reaction in which ozone (O_3) reacts with nitric oxide (NO) to form oxygen (O_2) and nitrogen dioxide (NO_2). During this reaction, a photon with a specific ultraviolet wavelength is emitted which is detected by a photomultiplier tube. The instrument is capable of analyzing total oxides of nitrogen ($NO + NO_2$) by thermally converting NO_2 to NO in a separate reaction chamber prior to the photomultiplier tube, if desired. The analyzer is operated in the NO_X mode during sampling.

A converter efficiency test is performed on the Thermo Electron Model 10S before the test series. During this procedure, a leak-free Tedlar bag is partially filled with a Protocol 1 NO_X reference gas. The Tedlar bag is then filled to capacity with a Certified Oxygen reference gas standard. The contents are well mixed and immediately connected to the sample inlet of the analyzer. The Tedlar bag is analyzed by the analyzer in the "NO_X" mode for at least thirty minutes. As the oxygen is exposed to the NO in the bag, the NO begins to react to form NO_2. A decrease in response in the NO_X mode of more than 2% absolute indicates that corrective action is required.

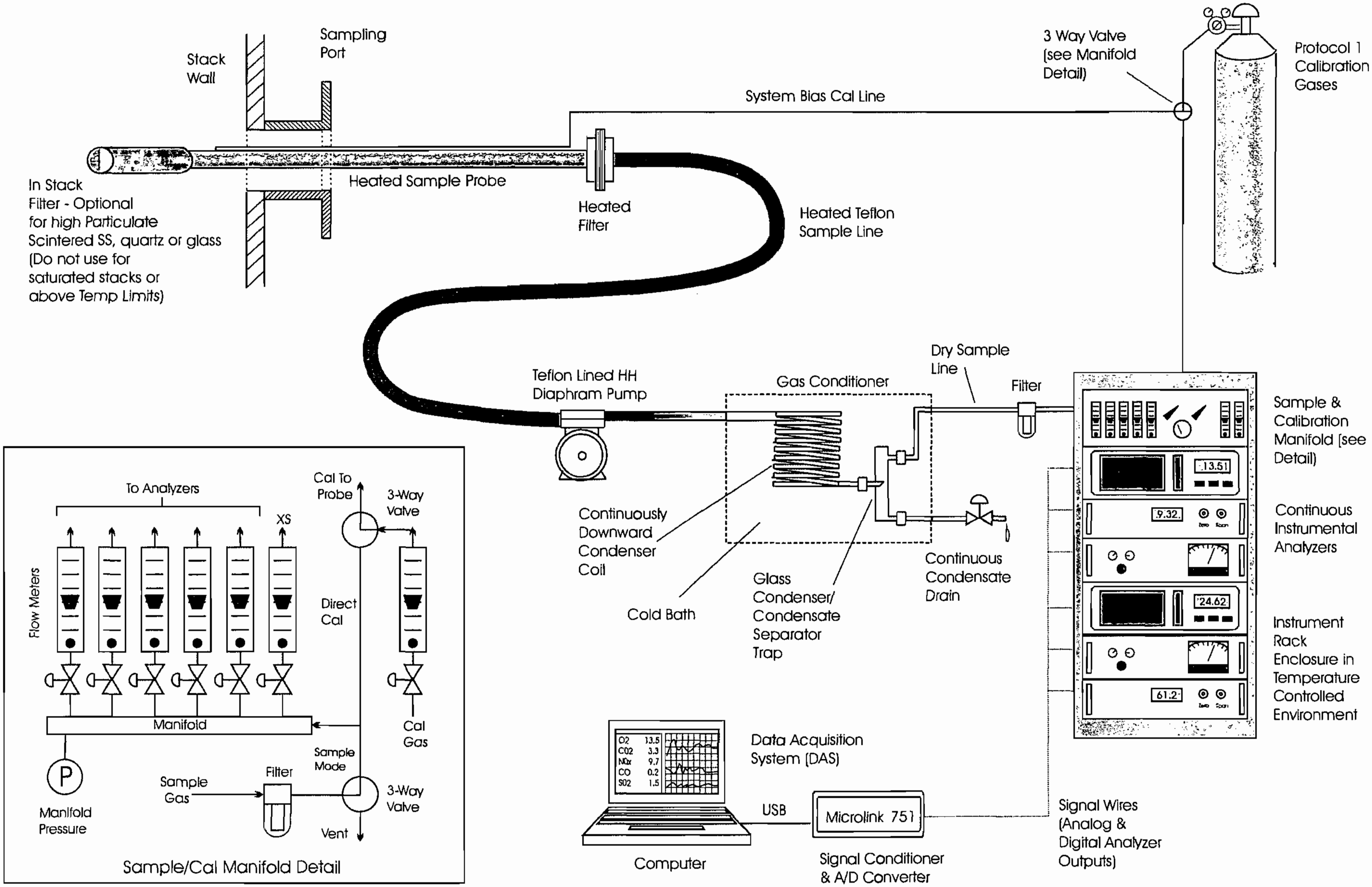


Figure 4-1. Schematic Diagram of STACS Instrumental Reference Method System

5.0 QUALITY ASSURANCE/QUALITY CONTROL

5.0 QUALITY ASSURANCE/QUALITY CONTROL

Strict Quality Assurance/Quality Control (QA/QC) measures were observed for all sampling and analysis performed for the Rayonier test program. The STACS QA/QC program is designed to provide the highest quality data in terms of the accuracy and precision of the measurements as well as the representativeness and comparability of the results.

Accuracy is the degree to which a measurement agrees to the true value or to an accepted reference value. Precision is the degree of reproducibility (or agreement) of a set of individual measurements of an identical property.

The objective of the overall QA/QC program is to provide guidelines in terms of accuracy and precision, which can be used to assess the uncertainty in the results and to substantiate the data in terms of the use of, accepted procedures. Quality Control can be defined as the use of operational techniques and activities that sustain good quality data. Adherence to accepted sampling and analytical methods and procedures (and specifically noting any aberrations or exceptions to these procedures) is an example of quality control. Quality Assurance includes all those planned and systematic activities necessary to ensure that the accuracy and precision of the results meets the needs of the testing program.

The QA program includes the activities planned by routine operators and analysts to provide an assessment of test data precision (and accuracy). Examples of implementation of QA measures include routine calibration checks to assess the bias and drift of an analyzer after each test run. The measurement system bias is an indicator of the accuracy of the system and the drift is an indication of the precision of the measurements.

The quality assurance/quality control measures for sampling and analysis included in the following documents were strictly followed during the emissions test program, except as noted below and elsewhere in this document. The procedures are incorporated by reference into the quality assurance program for this effort as they apply to the collection, analysis, and calculation of pollutant concentrations and mass emission rates from the combustion turbines:

> The Code of Federal Regulations, Title 40, Part 60, Appendix A., EPA Methods 1, 2, 3A, 4, 5,6C, 7E, 10.
>
> The Quality Assurance Handbook for Air Pollution Measurement Systems - Volume III - Stationary Source Specific Methods (EPA-600/4-77-027b) Sections 3.0-3.4.

The following sections provide a brief synopsis of the internal QA program that is used for this test program. Quality assurance documentation is included in Appendix C.

5.1 CALIBRATIONS AND DRIFT ASSESSMENTS

At the beginning of each test day, the EPA Reference Method 6C, 7E, 10 and 3A test equipment is calibrated, and adjusted as required, on a two-point basis. EPA Protocol #1, NIST traceable standard calibration gases are used to calibrate the analyzers. Subsequently, additional calibration standards are introduced to the analyzers to check the linearity of the instrument response. If the linearity of the instrument is within +/-2% of full scale of the calibration standard value, the calibration is accepted. Otherwise, corrective maintenance is performed, and the instrument is re-calibrated. During this time, bias checks are also performed by introducing calibration standards directly to the instrument manifold and through the entire sampling system and comparing the results.

Calibration checks are performed through the entire sampling system at the conclusion of each test run to determine calibration drift and any change in sample system bias. EPA Methods 3A and 7E require a bias/drift correction to be applied to the test data for each run based on pre-test and post-test bias and drift calibration checks. All data were bias/drift corrected for this program for consistency and in the interest of obtaining the highest quality data. The equation used for the bias corrections is provided in EPA Method 6C (Equation 6C-1).

Sampling system bias is assessed by introducing a mid-range or high-range gas through the sampling system and back to the analyzers. The maximum allowable bias is 5% of the value the analyzer read for the same gas when introduced to the probe tip as a percent of the span of the analyzer. STACS' internal QA/QC program requires that corrective action be taken if the bias exceeds 2% of the span.

Sampling system drift checks are subsequently performed at the conclusion of each test run. Corrective actions are taken if the drift checks exceed 2% of span after any test run. All calibration gases were EPA Protocol 1, NIST traceable standards with a rated accuracy of +/- 1%. Calibration gas analysis certificates are included in the test report.

5.2 NO_2 CONVERTER EFFICIENCY

Prior to the test series, an NO_2 to NO converter efficiency test is performed for the NO_X analyzer as prescribed in EPA Method 7E and 20. The procedure used for testing the converter efficiency is given below:

- Fill a leak-free Tedlar bag approximately half full with an NO in N_2 blend.
- Fill the remainder of the bag with 0.1 UHP grade air.
- Immediately attach the NO/Air mixture to the inlet of the NO_X monitor being used.
- Allow the monitor to sample the gas in the bag for 30 minutes.

As the O_2 and NO in the bag are exposed to each other a reaction occurs which changes the NO to NO_2. An attenuation in response over time of greater than two percent absolute indicates that the converter efficiency is unacceptable. Two NO_X analyzers were used for this test program

5.3 INSTRUMENT RESPONSE TIME

Maximum instrument system response time is determined by alternately passing zero and span gas through the entire sampling system and noting the time required for the monitors to achieve a change of 95% of the final concentrations. Both upscale and down scale response times are recorded. The supporting data sheets and DAS printouts are included in the test report.

5.4 LEAK CHECKS

Since all calibration drift and bias are performed through the entire sampling system, leak-checks are incorporated before and after each run. The criterion used for this test is an oxygen response to a zero gas of less than 0.5% O_2. Leak checks are also incorporated into the zero and span drift checks at the end of each run since the calibration gas is passed through the entire sampling system for each post test drift check. Acceptable bias checks are therefore also an indication that leakage is not occurring in the system. In addition, STACS conducts a vacuum leak check prior to initial sampling.

APPENDIX A

EMISSION DATA AND SAMPLE CALCULATIONS

To Convert Pollutant Concentrations to 7% O_2

$$ppmV\ @7\%\ O_2 = ppmV\ x\ \frac{13.9}{20.9 - O_2}$$

Where:

ppmV = The concentration of the pollutant in parts per million by volume, dry basis.

O_2 = The concentration of O_2 in percent volume, dry basis.

ppmV @ 7% O_2 = The concentration of the pollutant normalized to 7% O_2.

To Convert Pollutant Concentrations to 3% O_2

$$ppmV\ @3\%\ O_2 = ppmV\ x\ \frac{17.9}{20.9 - O_2}$$

Where:

ppmV = The concentration of the pollutant in parts per million by volume, dry basis.

O_2 = The concentration of O_2 in percent volume, dry basis.

ppmV @ 3% O_2 = The concentration of the pollutant normalized to 3% O_2.

To Convert Pollutant Concentrations to lb/MMBtu

$$lb/MMBtu = ppmV \; x \; CONV \; x \; F_d \; x \frac{20.9}{20.9 - O_2}$$

where:

ppmV = The concentration of the pollutant in parts per million by volume, dry basis.

O_2 = The concentration of oxygen in percent volume, dry basis.

lb/MMBtu = Pollutant emission rate in pounds per million Btu.

F_d = The oxygen based dry F-factor for a given fuel in scf@0% O_2/MMBtu (8710 for Natural Gas and 9190 for fuel oil).

CONV = conversion factor to convert pollutant concentration in ppmV to lb/scf.

CONV = 1.194 x 10^{-7} lb/scf $ ppmV for NO_X.

TO BIAS/DRIFT CORRECT RAW DATA FOR EPA METHODS 3A, 6C, AND 7E:

$$C_{gas} = (\overline{C} - C_o)\frac{C_{ma}}{C_m - C_o} \qquad \text{Eq. 6C-1}$$

Where:

C_{gas} = Effluent gas concentration, dry basis, ppm V or %V

$\underline{C}$ = Average gas concentration indicated by gas analyzer, dry basis, ppm V or %V

C_o = Average of initial and final system calibration bias check responses for the zero gas, ppm V or %V

C_m = Average of initial and final system calibration bias check responses for the upscale calibration gas, ppm V or %V

C_{ma} = Actual concentration of the upscale calibration gas, ppm V or %V

Source Testing And Consulting Services, Inc.

Scrubber B - Power Boiler 3

8-Jul-05 RAYONIER Fuel: Bark Unit # SCRUBBER B

	Parameter	O2	NOx	CO	CO2	NOx	CO	0.00	0.00	Comments
	Units	%V	ppmV	ppmV	%	@15%O2	@15%O2	0.00	0.00	
8-Jul-05	8:10:49	20.09	0.26	1.28	1.04	1.86	9.31			ce o2=20.0
8-Jul-05	8:10:54	20.12	0.26	1.38	1.04	1.93	10.38			ce o2=20.0
8-Jul-05	8:10:59	20.12	0.26	0.49	1.03	1.93	3.71			ce o2=20.0
8-Jul-05	8:11:04	20.09	0.26	0.39	1.00	1.85	2.85			ce o2=20.0
8-Jul-05	8:11:09	20.12	0.26	0.29	1.04	1.93	2.23			ce o2=20.0
8-Jul-05	8:11:14	20.10	0.26	0.39	1.01	1.88	2.89			ce o2=20.0
8-Jul-05	8:11:19	20.16	0.27	0.39	1.02	2.12	3.14			ce o2=20.0
8-Jul-05	8:11:24	20.13	0.26	0.39	1.03	1.96	3.01			ce o2=20.0
8-Jul-05	8:11:29	20.10	0.26	0.39	1.00	1.89	2.91			ce o2=20.0
8-Jul-05	8:11:39	20.12	0.27	0.39	1.00	2.01	2.98			lb
8-Jul-05	8:11:44	20.12	0.27	0.39	1.01	2.00	2.96			lb
8-Jul-05	8:11:49	20.16	0.27	0.49	1.03	2.12	3.93			lb
8-Jul-05	8:11:54	20.08	0.26	0.29	1.00	1.84	2.12			lb
8-Jul-05	8:11:59	20.13	0.26	0.29	1.00	1.96	2.27			lb
8-Jul-05	8:12:04	20.09	0.27	0.39	1.00	1.93	2.87			lb
8-Jul-05	8:12:09	20.12	0.26	0.29	1.00	1.92	2.22			lb
8-Jul-05	8:12:14	20.20	0.27	0.39	1.03	2.22	3.30			lb
8-Jul-05	8:12:19	20.14	0.26	0.39	1.03	1.98	3.04			lb
8-Jul-05	8:12:24	20.16	0.26	0.49	1.03	2.05	3.94			lb
8-Jul-05	8:12:29	20.13	0.26	0.39	1.00	1.96	3.02			lb
8-Jul-05	8:12:34	20.17	0.27	0.49	1.00	2.15	3.98			lb
8-Jul-05	8:12:39	20.15	0.27	0.39	1.03	2.09	3.09			lb
8-Jul-05	8:12:44	20.10	0.27	0.29	1.00	1.96	2.18			lb
8-Jul-05	8:12:49	20.15	0.27	0.39	1.03	2.09	3.10			lb
8-Jul-05	8:12:54	20.11	0.26	0.49	1.00	1.91	3.67			lb
8-Jul-05	8:12:59	20.13	0.27	0.39	1.00	2.02	2.99			lb
8-Jul-05	8:13:04	20.10	0.27	0.39	1.01	1.96	2.90			lb
8-Jul-05	8:13:09	20.19	0.26	0.39	1.00	2.12	3.26			lb
8-Jul-05	8:13:14	20.13	0.25	0.39	0.99	1.87	2.99			lb
8-Jul-05	8:13:19	20.12	0.26	0.29	1.00	1.94	2.24			lb
8-Jul-05	8:13:24	20.13	0.27	0.39	1.00	2.03	3.00			lb
8-Jul-05	8:13:29	20.14	0.26	0.39	1.03	1.99	3.06			lb
8-Jul-05	8:13:34	20.19	0.26	0.39	1.01	2.14	3.28			lb
8-Jul-05	8:14:45	12.49	0.24	0.39	1.00	0.17	0.28			ce o2=12.53
8-Jul-05	8:14:51	12.53	0.26	0.39	1.01	0.18	0.28			ce o2=12.53
8-Jul-05	8:14:56	12.52	0.26	0.49	1.01	0.18	0.35			ce o2=12.53
8-Jul-05	8:15:01	12.54	0.27	0.39	1.03	0.19	0.28			ce o2=12.53
8-Jul-05	8:15:06	12.56	0.26	0.39	1.03	0.18	0.28			ce o2=12.53
8-Jul-05	8:15:12	12.50	0.27	0.49	1.00	0.19	0.35			lb
8-Jul-05	8:15:17	12.56	0.26	0.39	0.99	0.18	0.28			lb
8-Jul-05	8:15:22	12.51	0.26	0.39	0.99	0.18	0.28			lb
8-Jul-05	8:15:27	12.51	0.25	0.29	0.99	0.17	0.21			lb
8-Jul-05	8:15:32	12.48	0.26	0.39	1.01	0.18	0.28			lb
8-Jul-05	8:15:37	12.53	0.27	0.39	1.03	0.19	0.28			lb
8-Jul-05	8:15:42	12.58	0.27	0.39	1.00	0.19	0.28			lb
8-Jul-05	8:15:47	12.53	0.26	0.29	0.99	0.18	0.21			lb
8-Jul-05	8:21:40	0.10	110.00	901.03	0.97	31.20	266.10			ce co=905
8-Jul-05	8:21:45	0.00	110.00	903.06	0.97	31.05	272.42			ce co=905
8-Jul-05	8:21:50	0.03	110.00	906.04	0.96	31.09	269.94			ce co=905
8-Jul-05	8:21:55	0.11	110.00	911.04	1.00	31.22	262.86			ce co=905
8-Jul-05	8:22:00	0.07	110.00	916.04	1.00	31.16	262.33			ce co=905
8-Jul-05	8:22:05	0.12	110.00	912.01	0.99	31.23	250.45			ce co=905
8-Jul-05	8:22:10	0.06	110.00	913.92	1.00	31.14	244.59			ce co=905
8-Jul-05	8:22:15	0.08	110.00	919.04	1.00	31.17	246.24			ce co=905
8-Jul-05	8:22:20	0.00	110.00	911.00	1.00	31.06	257.22			ce co=905

Source Testing And Consulting Services, Inc.
Scrubber B - Power Boiler 3

8-Jul-05 RAYONIER Fuel: Bark Unit # SCRUBBER B

Parameter		O2	NOx	CO	CO2	NOx	CO	0.00	0.00	Comments
Units		%V	ppmV	ppmV	%	@15%O2	@15%O2	0.00	0.00	
8-Jul-05	8:22:25	0.07	110.00	901.96	0.98	31.16	255.54			ce co=905
8-Jul-05	8:22:34	0.06	110.00	901.96	1.00	31.14	255.36			lb
8-Jul-05	8:22:39	0.04	110.00	894.00	0.96	31.11	252.80			lb
8-Jul-05	8:22:44	0.05	110.00	894.00	0.99	31.12	252.95			lb
8-Jul-05	8:22:49	0.10	110.00	896.06	1.00	31.20	254.17			lb
8-Jul-05	8:22:54	0.04	110.00	896.06	0.97	31.12	253.48			lb
8-Jul-05	8:22:59	0.07	110.00	900.98	0.96	31.16	255.26			lb
8-Jul-05	8:23:04	0.04	110.00	900.98	0.98	31.12	254.87			lb
8-Jul-05	8:25:47	0.07	110.00	615.95	0.95	31.15	174.45			ce co=619
8-Jul-05	8:25:52	0.03	110.00	625.88	0.96	31.09	176.92			ce co=619
8-Jul-05	8:25:57	0.10	110.00	623.91	0.97	31.20	176.97			ce co=619
8-Jul-05	8:26:02	0.04	110.00	623.91	0.95	31.11	176.43			ce co=619
8-Jul-05	8:26:07	0.10	110.00	614.87	0.96	31.20	174.41			ce co=619
8-Jul-05	8:26:12	0.06	110.00	614.87	0.95	31.13	174.04			ce co=619
8-Jul-05	8:26:17	0.03	110.00	617.82	0.96	31.10	174.69			ce co=619
8-Jul-05	8:26:22	-0.01	110.00	617.82	0.96	31.04	174.36			ce co=619
8-Jul-05	8:26:27	0.08	110.00	621.85	0.95	31.18	176.26			ce co=619
8-Jul-05	8:26:33	0.08	110.00	621.85	0.96	31.18	176.24			lb
8-Jul-05	8:26:38	0.10	110.00	627.84	0.98	31.21	178.13			lb
8-Jul-05	8:26:43	0.06	110.00	627.84	0.99	31.15	177.77			lb
8-Jul-05	8:26:48	0.10	110.00	623.82	0.97	31.21	176.99			lb
8-Jul-05	8:26:53	-0.01	110.00	623.82	0.97	31.03	175.99			lb
8-Jul-05	8:26:58	0.06	110.00	621.85	0.96	31.14	176.05			lb
8-Jul-05	8:28:47	0.10	110.00	308.68	0.95	31.20	87.56			ce co=306
8-Jul-05	8:28:52	0.04	110.00	306.62	0.98	31.11	86.72			ce co=306
8-Jul-05	8:28:57	0.07	110.00	305.64	0.97	31.16	86.58			ce co=306
8-Jul-05	8:29:02	0.01	110.00	305.64	0.94	31.07	86.34			ce co=306
8-Jul-05	8:29:07	0.04	110.00	302.69	0.96	31.11	85.61			ce co=306
8-Jul-05	8:29:12	-0.01	110.00	302.69	0.96	31.04	85.41			ce co=306
8-Jul-05	8:29:17	0.08	110.00	305.64	0.96	31.17	86.60			ce co=306
8-Jul-05	8:29:22	0.05	110.00	305.64	0.98	31.13	86.50			ce co=306
8-Jul-05	8:29:27	0.09	110.00	306.72	0.94	31.18	86.95			ce co=306
8-Jul-05	8:29:32	0.04	110.00	306.72	0.94	31.12	86.76			ce co=306
8-Jul-05	8:29:37	-0.02	110.00	306.62	0.94	31.02	86.46			ce co=306
8-Jul-05	8:29:42	0.05	110.00	306.62	0.94	31.12	86.75			ce co=306
8-Jul-05	8:29:47	0.06	110.00	305.64	0.98	31.14	86.52			ce co=306
8-Jul-05	8:29:52	0.01	110.00	305.73	0.94	31.07	86.35			ce co=306
8-Jul-05	8:29:57	-0.02	110.00	304.65	0.94	31.02	85.92			ce co=306
8-Jul-05	8:30:02	0.00	110.00	304.65	0.94	31.05	86.01			ce co=306
8-Jul-05	8:30:07	0.07	110.00	305.64	0.97	31.16	86.58			ce co=306
8-Jul-05	8:30:12	-0.02	110.00	305.73	0.95	31.03	86.23			ce co=306
8-Jul-05	8:30:17	0.03	110.00	306.62	0.96	31.10	86.70			ce co=306
8-Jul-05	8:30:22	0.03	110.00	306.62	0.94	31.09	86.66			ce co=306
8-Jul-05	8:30:27	0.05	110.00	305.73	0.97	31.13	86.52			ce co=306
8-Jul-05	8:30:35	0.03	110.00	305.64	0.94	31.10	86.41			lb
8-Jul-05	8:30:40	0.04	110.00	305.64	0.97	31.11	86.45			lb
8-Jul-05	8:30:45	0.04	110.00	303.67	0.97	31.12	85.90			lb
8-Jul-05	8:30:50	0.02	110.00	303.67	0.94	31.08	85.80			lb
8-Jul-05	8:30:55	0.09	110.00	304.65	0.96	31.19	86.38			lb
8-Jul-05	8:31:00	-0.01	110.00	304.65	0.93	31.03	85.95			lb
8-Jul-05	8:31:05	0.07	110.00	305.54	0.96	31.16	86.54			lb
8-Jul-05	8:31:10	0.01	110.00	305.64	0.93	31.06	86.31			lb
8-Jul-05	8:31:15	-0.01	110.00	304.75	0.94	31.04	86.01			lb
8-Jul-05	8:31:20	0.08	110.00	304.75	0.96	31.18	86.38			lb
8-Jul-05	8:31:25	-0.01	110.00	304.65	0.93	31.04	85.97			lb

Source Testing And Consulting Services, Inc.

Scrubber B - Power Boiler 3

8-Jul-05 RAYONIER Fuel: Bark Unit # SCRUBBER B

	Parameter	O2	NOx	CO	CO2	NOx	CO	0.00	0.00	Comments
	Units	%V	ppmV	ppmV	%	@15%O2	@15%O2	0.00	0.00	
8-Jul-05	8:33:21	0.02	94.76	95.52	0.93	26.77	26.99			ce nx=94.4
8-Jul-05	8:33:26	0.01	94.93	95.52	0.93	26.81	26.98			ce nx=94.4
8-Jul-05	8:33:31	-0.03	94.93	95.52	0.94	26.77	26.93			ce nx=94.4
8-Jul-05	8:33:36	-0.01	95.11	95.52	0.95	26.84	26.96			ce nx=94.4
8-Jul-05	8:33:41	0.03	95.11	95.52	0.93	26.89	27.00			ce nx=94.4
8-Jul-05	8:33:46	0.01	95.11	95.52	0.93	26.87	26.98			ce nx=94.4
8-Jul-05	8:33:51	0.04	95.11	95.62	0.96	26.90	27.05			ce nx=94.4
8-Jul-05	8:33:56	0.02	95.11	97.49	0.93	26.87	27.55			ce nx=94.4
8-Jul-05	8:34:01	0.04	95.05	97.59	0.93	26.88	27.60			ce nx=94.4
8-Jul-05	8:34:06	0.05	95.06	96.51	0.96	26.90	27.31			ce nx=94.4
8-Jul-05	8:34:11	0.02	95.05	96.51	0.93	26.86	27.27			ce nx=94.4
8-Jul-05	8:34:16	0.00	94.99	96.51	0.93	26.82	27.25			lb
8-Jul-05	8:34:21	0.05	94.99	96.51	0.96	26.88	27.31			lb
8-Jul-05	8:34:26	0.04	94.99	96.51	0.93	26.87	27.29			lb
8-Jul-05	8:34:31	0.06	95.05	96.51	0.94	26.91	27.32			lb
8-Jul-05	8:34:36	0.04	95.06	96.51	0.95	26.88	27.29			lb
8-Jul-05	8:34:41	0.04	95.05	96.51	0.95	26.89	27.30			lb
8-Jul-05	8:39:19	0.01	44.81	46.48	0.92	12.65	13.13			ce nx=44.6
8-Jul-05	8:39:24	0.06	44.81	46.48	0.92	12.69	13.16			ce nx=44.6
8-Jul-05	8:39:29	0.02	44.81	46.48	0.92	12.66	13.13			ce nx=44.6
8-Jul-05	8:39:34	0.01	44.81	46.48	0.92	12.66	13.13			ce nx=44.6
8-Jul-05	8:39:39	0.07	44.81	47.57	0.95	12.69	13.47			ce nx=44.6
8-Jul-05	8:39:44	0.00	44.81	46.48	0.92	12.65	13.12			ce nx=44.6
8-Jul-05	8:39:49	0.00	44.81	46.48	0.93	12.65	13.12			ce nx=44.6
8-Jul-05	8:39:54	0.00	44.81	46.48	0.92	12.65	13.12			ce nx=44.6
8-Jul-05	8:39:59	0.05	44.81	46.48	0.94	12.68	13.16			ce nx=44.6
8-Jul-05	8:40:04	0.01	44.75	46.48	0.92	12.64	13.13			ce nx=44.6
8-Jul-05	8:40:09	0.08	44.75	46.48	0.96	12.68	13.17			ce nx=44.6
8-Jul-05	8:40:14	0.08	44.75	46.48	0.95	12.68	13.17			ce nx=44.6
8-Jul-05	8:40:19	0.01	44.76	46.48	0.92	12.64	13.13			ce nx=44.6
8-Jul-05	8:40:24	0.05	44.75	46.48	0.96	12.66	13.15			ce nx=44.6
8-Jul-05	8:40:29	0.01	44.75	46.48	0.92	12.64	13.13			ce nx=44.6
8-Jul-05	8:40:34	-0.02	44.75	46.48	0.94	12.62	13.11			ce nx=44.6
8-Jul-05	8:40:41	0.04	44.75	46.48	0.95	12.66	13.15			lb
8-Jul-05	8:40:46	-0.01	44.75	46.58	0.93	12.63	13.14			lb
8-Jul-05	8:40:51	0.07	44.75	46.48	0.93	12.67	13.16			lb
8-Jul-05	8:40:56	0.00	44.71	46.58	0.93	12.62	13.15			lb
8-Jul-05	8:41:01	0.05	44.70	46.48	0.93	12.64	13.15			lb
8-Jul-05	8:41:06	0.01	44.73	46.48	0.92	12.63	13.13			lb
8-Jul-05	8:41:11	0.05	44.75	46.58	0.93	12.67	13.18			lb
8-Jul-05	8:52:38	12.49	46.58	398.72	9.21	32.68	279.73			ce co2=9.1
8-Jul-05	8:52:43	12.49	46.57	255.63	9.22	32.67	179.29			ce co2=9.1
8-Jul-05	8:52:48	12.45	27.11	94.55	9.23	18.93	66.04			ce co2=9.1
8-Jul-05	8:52:53 lb		27.11	94.55	9.22	18.92	65.98			ce co2=9.1
8-Jul-05	8:53:19	12.52	1.38	1.38	9.23	0.97	0.97			lb
8-Jul-05	8:53:24	12.52	1.38	0.39	9.24	0.97	0.28			lb
8-Jul-05	8:53:29	12.44	1.38	0.39	9.25	0.96	0.27			lb
8-Jul-05	8:55:03	12.46	1.14	0.29	18.16	0.80	0.21			ce co2=18.2
8-Jul-05	8:55:08	12.52	0.74	0.39	18.19	0.52	0.28			ce co2=18.2
8-Jul-05	8:55:13	12.49	0.73	0.39	18.24	0.51	0.28			ce co2=18.2
8-Jul-05	8:55:18	12.48	0.73	0.39	18.24	0.51	0.28			ce co2=18.2
8-Jul-05	8:55:23	12.53	0.50	0.49	18.16	0.35	0.35			lb
8-Jul-05	8:55:28	12.45	0.49	0.39	18.17	0.34	0.27			lb
8-Jul-05	8:55:33	12.46	0.50	0.39	18.16	0.35	0.27			lb
8-Jul-05	8:55:38	12.48	0.49	0.39	18.22	0.34	0.28			lb

Source Testing And Consulting Services, Inc.

Scrubber B - Power Boiler 3

8-Jul-05		RAYONIER		Fuel:	Bark			Unit #	SCRUBBER B	
	Parameter	O2	NOx	CO	CO2	NOx	CO	0.00	0.00	Comments
	Units	%V	ppmV	ppmV	%	@15%O2	@15%O2	0.00	0.00	
8-Jul-05	8:59:39	12.02	53.72	276.66	8.66	35.71	183.88			SCRUBBER START
8-Jul-05	9:00:39	11.91	44.18	354.79	8.52	29.00	232.92			SCRUBBER B R1
8-Jul-05	9:01:39	13.61	56.78	267.62	7.44	45.92	216.46			SCRUBBER B R1
8-Jul-05	9:02:39	14.21	55.83	281.57	6.80	49.24	248.33			SCRUBBER B R1
8-Jul-05	9:03:39	13.73	55.54	254.64	7.00	45.71	209.60			SCRUBBER B R1
8-Jul-05	9:04:39	12.70	57.53	259.66	7.96	41.38	186.78			SCRUBBER B R1
8-Jul-05	9:05:39	13.28	59.06	264.67	7.68	45.73	204.93			SCRUBBER B R1
8-Jul-05	9:06:39	13.90	57.59	250.71	7.05	48.54	211.29			SCRUBBER B R1
8-Jul-05	9:07:39	13.06	57.95	231.55	7.69	43.62	174.28			SCRUBBER B R1
8-Jul-05	9:08:39	12.39	63.40	195.58	8.12	43.95	135.57			SCRUBBER B R1
8-Jul-05	9:09:39	12.51	61.52	210.52	8.10	43.24	147.97			SCRUBBER B R1
8-Jul-05	9:10:39	11.90	59.53	217.59	8.69	39.03	142.67			SCRUBBER B R1
8-Jul-05	9:11:39	11.57	51.73	337.69	8.76	32.72	213.54			SCRUBBER B R1
8-Jul-05	9:12:39	11.59	65.34	199.61	8.95	41.39	126.46			SCRUBBER B R1
8-Jul-05	9:13:39	10.71	64.05	255.63	9.55	37.08	148.01			SCRUBBER B R1
8-Jul-05	9:14:39	10.33	40.88	1,001.08	9.90	22.82	558.88			SCRUBBER B R1
8-Jul-05	9:15:39	11.30	33.68	1,000.98	9.19	20.71	615.49			SCRUBBER B R1
8-Jul-05	9:16:39	10.93	66.57	224.67	9.49	39.38	132.90			SCRUBBER B R1
8-Jul-05	9:17:39	11.27	48.45	342.60	9.13	29.69	209.96			SCRUBBER B R1
8-Jul-05	9:18:39	11.43	62.11	273.61	9.04	38.72	170.55			SCRUBBER B R1
8-Jul-05	9:19:39	11.68	59.88	206.59	8.67	38.30	132.13			SCRUBBER B R1
8-Jul-05	9:20:39	11.78	58.89	206.59	8.50	38.11	133.70			SCRUBBER B R1
8-Jul-05	9:21:39	10.99	55.83	406.68	9.17	33.23	242.07			SCRUBBER B R1
8-Jul-05	9:22:39	12.45	55.96	247.67	8.34	39.09	173.02			SCRUBBER B R1
8-Jul-05	9:23:39	12.92	63.40	203.64	7.81	46.86	150.51			SCRUBBER B R1
8-Jul-05	9:24:39	10.84	53.42	403.74	9.24	31.32	236.76			SCRUBBER B R1
8-Jul-05	9:25:39	11.74	38.72	650.81	8.74	24.94	419.23			SCRUBBER B R1
8-Jul-05	9:26:39	12.22	55.08	262.70	8.42	37.45	178.61			SCRUBBER B R1
8-Jul-05	9:27:39	12.72	60.18	232.73	8.06	43.41	167.88			SCRUBBER B R1
8-Jul-05	9:28:39	13.02	58.76	233.61	7.69	43.99	174.88			SCRUBBER B R1
8-Jul-05	9:29:39	11.23	57.19	371.70	9.02	34.89	226.78			SCRUBBER B R1
8-Jul-05	9:30:39	10.47	48.23	653.86	9.81	27.28	369.80			SCRUBBER B R1
8-Jul-05	9:31:39	11.37	44.24	464.87	9.20	27.38	287.72			SCRUBBER B R1
8-Jul-05	9:32:39	11.93	51.21	354.69	8.81	33.70	233.43			SCRUBBER B R1
8-Jul-05	9:33:39	11.30	55.83	248.65	8.73	34.30	152.75			SCRUBBER B R1
8-Jul-05	9:34:39	11.49	50.39	523.74	8.84	31.58	328.21			SCRUBBER B R1
8-Jul-05	9:35:39	12.10	59.82	232.63	8.46	40.11	155.96			SCRUBBER B R1
8-Jul-05	9:36:39	11.74	62.58	207.67	8.75	40.29	133.70			SCRUBBER B R1
8-Jul-05	9:37:39	12.64	62.41	220.64	7.98	44.55	157.51			SCRUBBER B R1
8-Jul-05	9:38:39	12.07	61.59	209.63	8.51	41.13	139.99			SCRUBBER B R1
8-Jul-05	9:39:39	11.28	59.12	234.60	9.07	36.26	143.90			SCRUBBER B R1
8-Jul-05	9:40:39	11.79	55.02	240.69	8.57	35.61	155.79			SCRUBBER B R1
8-Jul-05	9:41:39	12.83	60.41	220.64	7.96	44.19	161.39			SCRUBBER B R1
8-Jul-05	9:42:39	11.95	62.53	223.59	8.46	41.24	147.47			SCRUBBER B R1
8-Jul-05	9:43:39	13.21	60.19	244.64	7.60	46.17	187.67			SCRUBBER B R1
8-Jul-05	9:44:39	12.32	60.65	245.63	8.13	41.73	168.99			SCRUBBER B R1
8-Jul-05	9:45:39	11.15	54.90	309.71	9.25	33.23	187.46			SCRUBBER B R1
8-Jul-05	9:46:39	12.43	53.32	268.63	8.38	37.12	187.01			SCRUBBER B R1
8-Jul-05	9:47:39	12.43	58.41	206.61	8.25	40.69	143.92			SCRUBBER B R1
8-Jul-05	9:48:39	13.19	57.25	220.66	7.73	43.79	168.79			SCRUBBER B R1
8-Jul-05	9:49:39	13.26	57.25	210.64	7.60	44.19	162.57			SCRUBBER B R1
8-Jul-05	9:50:39	13.49	57.66	197.66	7.50	45.93	157.47			SCRUBBER B R1
8-Jul-05	9:51:39	13.30	57.61	203.56	7.49	44.72	158.02			SCRUBBER B R1
8-Jul-05	9:52:39	12.84	56.55	211.72	7.88	41.37	154.89			SCRUBBER B R1
8-Jul-05	9:53:39	13.28	56.66	206.61	7.59	43.86	159.92			SCRUBBER B R1

Source Testing And Consulting Services, Inc.

Scrubber B - Power Boiler 3

8-Jul-05		RAYONIER	Fuel:	Bark			Unit #		SCRUBBER B
	Parameter	O2	NOx	CO	CO2	NOx	CO	0.00	0.00 Comments
	Units	%V	ppmV	ppmV	%	@15%O2	@15%O2	0.00	0.00
8-Jul-05	9:54:39	12.52	57.02	181.64	8.12	40.12	127.82		SCRUBBER B R1
8-Jul-05	9:55:39	11.89	55.26	201.69	8.55	36.18	132.06		SCRUBBER B R1
8-Jul-05	9:56:39	11.77	68.90	202.58	8.53	44.51	130.86		SCRUBBER B R1
8-Jul-05	9:57:39	12.27	97.31	234.62	8.20	66.51	160.36		SCRUBBER B R1
8-Jul-05	9:58:39	12.91	56.43	210.64	7.62	41.69	155.62		SCRUBBER B R1
8-Jul-05	9:59:39	11.84	57.61	195.70	8.57	37.51	127.41		SCRUBBER B R1
8-Jul-05	10:02:51	20.09	9.95	0.49	0.92	72.38	3.58		O2=20
8-Jul-05	10:02:56	19.98	0.68	0.29	0.89	4.35	1.89		O2=20
8-Jul-05	10:03:01	20.04	0.68	0.39	0.92	4.65	2.70		O2=20
8-Jul-05	10:03:06	20.02	0.50	0.49	0.89	3.36	3.30		O2=20
8-Jul-05	10:03:11	20.04	0.50	0.39	0.91	3.44	2.70		O2=20
8-Jul-05	10:04:24	12.56	0.62	0.39	0.88	0.44	0.28		O2=12.53
8-Jul-05	10:04:29	12.63	0.56	0.49	0.90	0.40	0.35		O2=12.53
8-Jul-05	10:04:34	12.51	0.56	0.49	0.88	0.39	0.35		O2=12.53
8-Jul-05	10:04:39	12.58	0.56	0.49	0.91	0.40	0.35		O2=12.53
8-Jul-05	10:04:44	12.56	0.43	0.39	0.88	0.31	0.28		O2=12.53
8-Jul-05	10:04:49	12.51	0.44	0.49	0.89	0.31	0.35		O2=12.53
8-Jul-05	10:04:54	12.60	0.44	0.39	0.91	0.31	0.28		O2=12.53
8-Jul-05	10:07:45	0.04	44.41	47.57	0.91	12.56	13.45		NOX=44.6
8-Jul-05	10:07:50	-0.01	44.41	47.47	0.91	12.53	13.39		NOX=44.6
8-Jul-05	10:07:55	0.03	44.41	47.47	0.88	12.56	13.42		NOX=44.6
8-Jul-05	10:08:00	0.07	44.41	47.47	0.89	12.58	13.44		NOX=44.6
8-Jul-05	10:08:05	0.03	44.41	48.55	0.89	12.55	13.72		NOX=44.6
8-Jul-05	10:08:10	0.03	44.40	48.55	0.88	12.55	13.72		NOX=44.6
8-Jul-05	10:08:15	0.03	44.41	47.47	0.88	12.55	13.42		NOX=44.6
8-Jul-05	10:08:20	0.04	44.41	47.47	0.88	12.56	13.42		NOX=44.6
8-Jul-05	10:08:25	0.06	44.41	48.55	0.91	12.57	13.74		NOX=44.6
8-Jul-05	10:08:30	0.10	44.40	48.55	0.90	12.59	13.77		NOX=44.6
8-Jul-05	10:08:35	0.03	44.40	47.57	0.88	12.55	13.45		NOX=44.6
8-Jul-05	10:08:40	0.05	44.41	47.57	0.91	12.57	13.46		NOX=44.6
8-Jul-05	10:08:45	0.03	44.41	47.57	0.88	12.56	13.45		NOX=44.6
8-Jul-05	10:08:50	0.05	44.41	47.47	0.91	12.57	13.43		NOX=44.6
8-Jul-05	10:11:04	0.06	93.07	98.47	0.91	26.34	27.87		NOX=94.4
8-Jul-05	10:11:09	-0.02	93.07	98.57	0.87	26.25	27.80		NOX=94.4
8-Jul-05	10:11:14	-0.01	93.29	98.57	0.90	26.33	27.82		NOX=94.4
8-Jul-05	10:11:19	-0.01	93.29	98.57	0.89	26.32	27.81		NOX=94.4
8-Jul-05	10:11:24	0.07	93.29	98.57	0.89	26.43	27.92		NOX=94.4
8-Jul-05	10:11:29	-0.02	93.29	98.57	0.87	26.31	27.80		NOX=94.4
8-Jul-05	10:11:34	0.03	93.13	99.55	0.90	26.33	28.14		NOX=94.4
8-Jul-05	10:11:39	0.05	93.12	99.55	0.90	26.35	28.17		NOX=94.4
8-Jul-05	10:11:44	0.01	93.13	99.55	0.87	26.30	28.12		NOX=94.4
8-Jul-05	10:11:49	-0.02	92.83	99.55	0.87	26.18	28.07		NOX=94.4
8-Jul-05	10:11:54	0.06	92.82	98.57	0.87	26.28	27.91		NOX=94.4
8-Jul-05	10:11:59	0.09	92.82	98.47	0.89	26.32	27.92		NOX=94.4
8-Jul-05	10:12:04	0.06	92.64	97.49	0.87	26.23	27.60		NOX=94.4
8-Jul-05	10:13:42	0.03	110.00	310.75	0.87	31.09	87.84		CO=306
8-Jul-05	10:13:47	-0.02	110.00	311.73	0.87	31.03	87.92		CO=306
8-Jul-05	10:13:52	0.05	110.00	309.67	0.91	31.12	87.61		CO=306
8-Jul-05	10:13:57	0.02	110.00	309.67	0.87	31.08	87.48		CO=306
8-Jul-05	10:14:02	0.02	110.00	309.67	0.87	31.08	87.48		CO=306
8-Jul-05	10:14:07	0.03	110.00	309.76	0.88	31.09	87.56		CO=306
8-Jul-05	10:16:19	0.03	110.00	890.96	0.90	31.09	251.83		CO=905
8-Jul-05	10:16:24	0.05	110.00	873.96	0.87	31.13	247.34		CO=905
8-Jul-05	10:16:29	0.05	110.00	873.86	0.90	31.12	247.23		CO=905
8-Jul-05	10:16:34	0.06	110.00	872.00	0.90	31.13	246.81		CO=905

Source Testing And Consulting Services, Inc.

Scrubber B - Power Boiler 3

8-Jul-05		RAYONIER		Fuel:	Bark			Unit #	SCRUBBER B	
	Parameter	O2	NOx	CO	CO2	NOx	CO	0.00	0.00	Comments
	Units	%V	ppmV	ppmV	%	@15%O2	@15%O2	0.00	0.00	
8-Jul-05	10:16:39	0.02	110.00	870.92	0.86	31.09	246.13			CO=905
8-Jul-05	10:16:44	0.01	110.00	882.91	0.88	31.07	249.40			CO=905
8-Jul-05	10:16:49	-0.02	110.00	883.00	0.86	31.02	249.02			CO=905
8-Jul-05	10:22:40	11.42	53.67	277.53	8.78	33.39	172.65			RUN2 START
8-Jul-05	10:23:40	11.42	53.20	250.60	9.00	33.10	155.94			RUN2
8-Jul-05	10:24:40	11.47	52.96	207.66	8.85	33.13	129.89			RUN2
8-Jul-05	10:25:40	11.72	48.51	322.74	8.63	31.17	207.38			RUN2
8-Jul-05	10:26:40	11.29	50.10	341.70	9.12	30.75	209.69			RUN2
8-Jul-05	10:27:40	12.27	58.24	193.60	8.25	39.80	132.30			RUN2
8-Jul-05	10:28:40	12.29	52.44	255.71	8.41	35.94	175.24			RUN2
8-Jul-05	10:29:40	13.45	58.24	210.60	7.50	46.14	166.85			RUN2
8-Jul-05	10:30:40	12.81	56.18	219.65	8.01	40.99	160.26			RUN2
8-Jul-05	10:31:40	11.92	58.59	206.58	8.52	38.51	135.79			RUN2
8-Jul-05	10:32:40	12.33	56.83	213.65	8.25	39.14	147.13			RUN2
8-Jul-05	10:33:40	12.30	56.89	197.63	8.34	39.02	135.55			RUN2
8-Jul-05	10:34:40	12.27	56.30	187.61	8.23	38.50	128.27			RUN2
8-Jul-05	10:35:40	12.17	53.02	207.56	8.31	35.83	140.28			RUN2
8-Jul-05	10:36:40	11.33	53.96	243.62	9.02	33.26	150.16			RUN2
8-Jul-05	10:37:40	11.45	53.73	195.67	8.76	33.54	122.17			RUN2
8-Jul-05	10:38:40	11.09	49.22	274.68	9.11	29.60	165.18			RUN2
8-Jul-05	10:39:40	11.12	44.22	423.67	9.27	26.67	255.49			RUN2
8-Jul-05	10:40:40	11.56	49.63	251.68	8.99	31.35	159.00			RUN2
8-Jul-05	10:41:40	11.09	47.63	375.71	9.37	28.64	225.88			RUN2
8-Jul-05	10:42:40	11.13	43.01	396.64	9.19	25.97	239.49			RUN2
8-Jul-05	10:43:40	12.32	43.70	254.60	8.36	30.05	175.06			RUN2
8-Jul-05	10:44:40	12.95	54.19	211.45	7.82	40.22	156.94			RUN2
8-Jul-05	10:45:40	12.28	54.66	197.59	8.19	37.40	135.21			RUN2
8-Jul-05	10:46:40	11.77	54.89	256.56	8.65	35.49	165.87			RUN2
8-Jul-05	10:47:40	11.69	51.79	232.58	8.69	33.19	149.04			RUN2
8-Jul-05	10:48:40	11.81	51.39	227.57	8.52	33.36	147.72			RUN2
8-Jul-05	10:49:40	11.90	49.27	264.62	8.70	32.32	173.55			RUN2
8-Jul-05	10:50:40	12.26	56.71	188.55	8.40	38.73	128.76			RUN2
8-Jul-05	10:51:40	11.82	59.41	174.60	8.54	38.58	113.39			RUN2
8-Jul-05	10:52:40	12.07	53.84	197.59	8.46	35.96	131.97			RUN2
8-Jul-05	10:53:40	11.53	53.72	219.61	8.93	33.84	138.33			RUN2
8-Jul-05	10:54:40	12.15	44.75	338.62	8.38	30.16	228.20			RUN2
8-Jul-05	10:55:40	13.41	53.48	197.40	7.37	42.14	155.55			RUN2
8-Jul-05	10:56:40	13.10	54.25	188.45	7.60	41.01	142.47			RUN2
8-Jul-05	10:57:40	13.33	55.00	204.57	7.69	42.86	159.42			RUN2
8-Jul-05	10:58:40	15.68	54.13	237.49	5.76	61.13	268.21			RUN2
8-Jul-05	10:59:40	16.74	35.08	312.68	4.68	49.75	443.42			RUN2
8-Jul-05	11:00:40	15.32	27.29	300.59	5.78	28.84	317.66			RUN2
8-Jul-05	11:01:40	15.35	44.87	221.57	5.83	47.71	235.60			RUN2
8-Jul-05	11:02:40	14.61	44.05	198.58	6.53	41.35	186.39			RUN2
8-Jul-05	11:03:40	13.86	50.56	173.56	6.98	42.39	145.53			RUN2
8-Jul-05	11:04:40	12.70	53.26	168.55	8.06	38.30	121.22			RUN2
8-Jul-05	11:05:40	12.30	56.71	167.57	8.03	38.92	115.00			RUN2
8-Jul-05	11:06:40	11.57	57.60	196.56	8.92	36.42	124.28			RUN2
8-Jul-05	11:07:40	11.33	52.96	215.63	8.93	32.65	132.94			RUN2
8-Jul-05	11:08:40	11.14	52.67	245.60	9.15	31.83	148.41			RUN2
8-Jul-05	11:09:40	11.38	51.85	232.63	8.99	32.15	144.24			RUN2
8-Jul-05	11:10:40	11.41	52.49	236.56	8.99	32.65	147.13			RUN2
8-Jul-05	11:11:40	10.81	51.21	318.72	9.39	29.96	186.45			RUN2
8-Jul-05	11:12:40	11.20	49.81	342.60	9.07	30.30	208.39			RUN2
8-Jul-05	11:13:40	12.55	57.01	236.56	8.08	40.30	167.23			RUN2

Source Testing And Consulting Services, Inc.

Scrubber B - Power Boiler 3

8-Jul-05	RAYONIER		Fuel:	Bark				Unit #	SCRUBBER B	
	Parameter	O2	NOx	CO	CO2	NOx	CO	0.00	0.00	Comments
	Units	%V	ppmV	ppmV	%	@15%O2	@15%O2	0.00	0.00	
8-Jul-05	11:14:40	12.80	59.35	221.62	7.94	43.23	161.42			RUN2
8-Jul-05	11:15:40	13.83	59.12	228.60	7.21	49.34	190.82			RUN2
8-Jul-05	11:16:40	15.55	57.83	272.63	5.82	63.73	300.47			RUN2
8-Jul-05	11:17:40	14.95	52.20	272.63	6.19	51.75	270.32			RUN2
8-Jul-05	11:18:40	15.27	52.27	261.62	5.77	54.81	274.36			RUN2
8-Jul-05	11:19:40	15.14	43.29	290.61	5.87	44.35	297.74			RUN2
8-Jul-05	11:20:40	14.97	44.47	257.69	6.17	44.28	256.57			RUN2
8-Jul-05	11:21:40	15.36	43.23	265.65	5.82	46.00	282.66			RUN2
8-Jul-05	11:23:47	12.58	22.83	15.48	0.89	16.20	10.98			O2-12.53
8-Jul-05	11:23:52	12.59	3.48	4.47	0.92	2.47	3.17			O2-12.53
8-Jul-05	11:23:57	12.53	1.03	4.47	0.90	0.72	3.15			O2-12.53
8-Jul-05	11:24:02	12.56	1.03	1.33	0.89	0.73	0.94			O2-12.53
8-Jul-05	11:24:07	12.58	1.04	1.42	0.91	0.74	1.01			O2-12.53
8-Jul-05	11:25:43	20.11	0.44	0.44	0.87	3.25	3.29			O2=20
8-Jul-05	11:25:48	20.10	0.39	0.54	0.90	2.88	4.00			O2=20
8-Jul-05	11:25:53	20.05	0.38	0.44	0.87	2.62	3.06			O2=20
8-Jul-05	11:25:58	20.03	0.38	0.44	0.87	2.57	3.01			O2=20
8-Jul-05	11:26:04	20.04	0.39	0.44	0.88	2.67	3.04			O2=20
8-Jul-05	11:26:09	20.08	0.38	0.44	0.91	2.72	3.18			O2=20
8-Jul-05	11:27:52	0.02	44.29	46.53	0.88	12.51	13.15			NOX=44.6
8-Jul-05	11:27:57	0.05	44.35	46.53	0.87	12.55	13.17			NOX=44.6
8-Jul-05	11:28:02	0.07	44.36	46.53	0.90	12.57	13.18			NOX=44.6
8-Jul-05	11:28:07	0.05	44.42	46.53	0.87	12.57	13.17			NOX=44.6
8-Jul-05	11:28:12	0.07	44.41	46.63	0.90	12.58	13.21			NOX=44.6
8-Jul-05	11:28:17	0.07	44.42	46.53	0.90	12.58	13.18			NOX=44.6
8-Jul-05	11:28:22	0.02	44.35	46.53	0.90	12.53	13.15			NOX=44.6
8-Jul-05	11:29:46	0.03	44.35	46.53	0.88	12.54	13.15			NOX=44.6
8-Jul-05	11:29:50	0.07	44.41	46.63	0.90	12.57	13.21			NOX=44.6
8-Jul-05	11:31:45 \		93.00	95.67	0.87	26.32	27.07			NOX=94.4
8-Jul-05	11:31:50	0.09	93.12	96.56	0.87	26.40	27.37			NOX=94.4
8-Jul-05	11:31:55	0.03	93.13	96.56	0.86	26.32	27.29			NOX=94.4
8-Jul-05	11:32:00	0.05	93.24	96.65	0.86	26.38	27.35			NOX=94.4
8-Jul-05	11:32:05	0.03	93.24	96.56	0.88	26.35	27.29			NOX=94.4
8-Jul-05	11:32:10	0.03	93.24	97.54	0.87	26.36	27.58			NOX=94.4
8-Jul-05	11:33:27	0.02	110.00	299.69	0.88	31.08	84.69			CO=306
8-Jul-05	11:33:32	0.02	110.00	300.67	0.89	31.08	84.94			CO=306
8-Jul-05	11:33:37	0.04	110.00	300.77	0.87	31.12	85.08			CO=306
8-Jul-05	11:33:43	0.05	110.00	298.71	0.89	31.12	84.51			CO=306
8-Jul-05	11:33:48	0.06	110.00	298.71	0.88	31.13	84.55			CO=306
8-Jul-05	11:37:50	14.53	64.93	89.58	7.36	60.12	82.95			RUN 3
8-Jul-05	11:38:50	11.34	53.38	196.60	8.84	32.94	121.33			RUN 3
8-Jul-05	11:39:50	11.07	43.53	451.82	9.04	26.13	271.24			RUN 3
8-Jul-05	11:40:50	12.40	46.17	309.72	8.47	32.05	214.95			RUN 3
8-Jul-05	11:41:50	11.89	55.84	174.59	8.45	36.54	114.26			RUN 3
8-Jul-05	11:42:50	11.22	55.55	264.70	8.91	33.87	161.41			RUN 3
8-Jul-05	11:43:50	11.11	48.33	344.67	9.09	29.14	207.78			RUN 3
8-Jul-05	11:44:50	10.71	51.10	323.74	9.62	29.57	187.35			RUN 3
8-Jul-05	11:45:50	10.50	51.56	603.83	9.49	29.26	342.68			RUN 3
8-Jul-05	11:46:50	10.76	40.02	718.92	9.58	23.28	418.27			RUN 3
8-Jul-05	11:47:50	11.02	49.09	251.60	9.03	29.32	150.28			RUN 3
8-Jul-05	11:48:50	11.49	56.60	234.69	8.91	35.47	147.10			RUN 3
8-Jul-05	11:49:50	12.44	58.59	198.62	8.06	40.85	138.48			RUN 3
8-Jul-05	11:50:50	12.54	58.53	183.59	8.16	41.28	129.50			RUN 3
8-Jul-05	11:51:50	12.31	61.70	192.63	8.35	42.40	132.38			RUN 3
8-Jul-05	11:52:50	12.65	62.05	196.56	8.03	44.36	140.51			RUN 3

Source Testing And Consulting Services, Inc.

Scrubber B - Power Boiler 3

8-Jul-05		RAYONIER		Fuel:	Bark			Unit #		SCRUBBER B
	Parameter	O2	NOx	CO	CO2	NOx	CO	0.00	0.00	Comments
	Units	%V	ppmV	ppmV	%	@15%O2	@15%O2	0.00	0.00	
8-Jul-05	11:53:50	12.97	62.87	216.51	7.50	46.78	161.10			RUN 3
8-Jul-05	11:54:50	13.11	61.23	208.65	7.71	46.35	157.94			RUN 3
8-Jul-05	11:55:50	13.68	59.65	234.60	7.01	48.73	191.65			RUN 3
8-Jul-05	11:56:50	13.43	57.42	212.58	7.58	45.35	167.90			RUN 3
8-Jul-05	11:57:50	15.14	55.37	252.68	6.05	56.67	258.60			RUN 3
8-Jul-05	11:58:50	14.56	49.87	250.61	6.21	46.43	233.32			RUN 3
8-Jul-05	11:59:50	14.12	55.14	227.62	6.67	47.96	198.01			RUN 3
8-Jul-05	12:00:50	13.01	58.48	190.57	7.72	43.71	142.45			RUN 3
8-Jul-05	12:01:50	12.46	59.06	203.54	8.14	41.27	142.23			RUN 3
8-Jul-05	12:02:50	12.14	55.02	227.62	8.36	37.04	153.26			RUN 3
8-Jul-05	12:03:50	13.38	55.30	221.62	7.39	43.39	173.87			RUN 3
8-Jul-05	12:04:50	12.46	54.90	167.57	8.09	38.38	117.15			RUN 3
8-Jul-05	12:05:50	12.89	55.49	209.63	7.84	40.88	154.42			RUN 3
8-Jul-05	12:06:50	12.36	54.96	202.56	8.29	37.97	139.94			RUN 3
8-Jul-05	12:07:50	12.24	54.20	191.55	8.28	36.93	130.49			RUN 3
8-Jul-05	12:08:50	12.51	54.78	178.58	7.96	38.52	125.57			RUN 3
8-Jul-05	12:09:50	11.55	59.49	169.63	8.70	37.54	107.06			RUN 3
8-Jul-05	12:10:50	11.18	44.29	432.73	9.26	26.88	262.68			RUN 3
8-Jul-05	12:11:50	10.74	48.98	324.72	9.43	28.43	188.49			RUN 3
8-Jul-05	12:12:50	10.79	44.76	483.74	9.46	26.11	282.23			RUN 3
8-Jul-05	12:13:50	10.26	47.64	596.86	9.81	26.41	330.86			RUN 3
8-Jul-05	12:14:50	10.74	35.62	718.82	9.57	20.68	417.36			RUN 3
8-Jul-05	12:15:50	11.18	43.23	478.82	9.18	26.23	290.51			RUN 3
8-Jul-05	12:16:50	10.58	44.71	631.74	9.56	25.57	361.29			RUN 3
8-Jul-05	12:17:50	11.56	44.87	342.60	8.86	28.35	216.45			RUN 3
8-Jul-05	12:18:50	11.59	53.84	205.60	8.54	34.13	130.34			RUN 3
8-Jul-05	12:19:50	10.93	55.08	540.74	9.53	32.61	320.15			RUN 3
8-Jul-05	12:20:50	10.76	45.29	673.81	9.59	26.34	391.88			RUN 3
8-Jul-05	12:21:50	12.19	49.45	228.60	8.27	33.50	154.86			RUN 3
8-Jul-05	12:22:50	11.64	59.41	226.54	8.55	37.86	144.38			RUN 3
8-Jul-05	12:23:50	12.87	55.83	236.66	8.02	41.00	173.80			RUN 3
8-Jul-05	12:24:50	12.49	58.54	246.68	8.03	41.07	173.06			RUN 3
8-Jul-05	12:25:50	13.48	60.35	262.60	7.36	47.99	208.82			RUN 3
8-Jul-05	12:26:50	14.75	55.19	296.71	6.42	52.91	284.45			RUN 3
8-Jul-05	12:27:50	14.57	59.23	318.72	6.50	55.22	297.13			RUN 3
8-Jul-05	12:28:50	14.63	53.55	313.71	6.33	50.39	295.21			RUN 3
8-Jul-05	12:29:50	15.75	43.88	341.62	5.37	50.30	391.61			RUN 3
8-Jul-05	12:30:50	15.47	40.36	359.71	5.31	43.86	390.88			RUN 3
8-Jul-05	12:31:50	14.65	40.42	323.74	6.13	38.16	305.60			RUN 3
8-Jul-05	12:32:50	14.34	50.74	246.59	6.32	45.62	221.70			RUN 3
8-Jul-05	12:33:50	13.77	51.79	227.62	7.05	42.86	188.36			RUN 3
8-Jul-05	12:34:50	14.27	53.02	225.65	6.32	47.16	200.70			RUN 3
8-Jul-05	12:35:50	13.35	51.50	213.66	7.42	40.23	166.92			RUN 3
8-Jul-05	12:36:50	11.39	55.02	187.62	8.20	34.15	116.45			RUN 3
8-Jul-05	12:37:50	11.19	62.40	172.58	8.94	37.93	104.89			RUN 3
8-Jul-05	12:38:50	11.09	61.23	112.53	8.81	36.84	67.71			RUN 3
8-Jul-05	12:42:19	0.03	43.41	47.57	0.87	12.27	13.45			NOX=44.4
8-Jul-05	12:42:24	0.07	43.53	47.47	0.90	12.33	13.44			NOX=44.4
8-Jul-05	12:42:29	0.03	43.53	47.47	0.86	12.30	13.42			NOX=44.4
8-Jul-05	12:42:34	0.03	43.53	47.47	0.86	12.30	13.42			NOX=44.4
8-Jul-05	12:42:39	0.06	43.65	47.57	0.90	12.36	13.47			NOX=44.4
8-Jul-05	12:42:44	0.05	43.65	47.57	0.89	12.35	13.46			NOX=44.4
8-Jul-05	12:42:49	0.03	43.65	47.47	0.86	12.34	13.42			NOX=44.4
8-Jul-05	12:42:54	0.09	43.76	47.47	0.90	12.41	13.46			NOX=44.4
8-Jul-05	12:42:59	0.09	43.76	47.47	0.89	12.41	13.46			NOX=44.4

Source Testing And Consulting Services, Inc.

Scrubber B - Power Boiler 3

8-Jul-05		RAYONIER	Fuel:	Bark				Unit #	SCRUBBER B
	Parameter	O2	NOx	CO	CO2	NOx	CO	0.00	0.00 Comments
	Units	%V	ppmV	ppmV	%	@15%O2	@15%O2	0.00	0.00
8-Jul-05	12:43:04	0.07	43.81	47.47	0.86	12.41	13.45		NOX=44.4
8-Jul-05	12:43:09	0.03	43.81	47.47	0.88	12.39	13.42		NOX=44.4
8-Jul-05	12:47:20	0.02	94.13	95.53	0.87	26.60	27.00		NOX=94.4
8-Jul-05	12:47:25	0.03	94.19	94.55	0.86	26.62	26.73		NOX=94.4
8-Jul-05	12:47:30	0.05	94.19	95.63	0.89	26.65	27.06		NOX=94.4
8-Jul-05	12:47:35	0.03	94.19	95.53	0.89	26.63	27.01		NOX=94.4
8-Jul-05	12:47:40	0.06	94.19	94.55	0.87	26.67	26.77		NOX=94.4
8-Jul-05	12:47:45	0.04	94.19	94.55	0.87	26.64	26.75		NOX=94.4
8-Jul-05	12:47:50	0.09	94.24	95.53	0.88	26.71	27.08		NOX=94.4
8-Jul-05	12:47:55	0.05	94.25	95.53	0.88	26.67	27.04		NOX=94.4
8-Jul-05	12:48:00	0.05	94.25	95.53	0.88	26.67	27.04		NOX=94.4
8-Jul-05	12:48:05	-0.03	94.25	95.53	0.85	26.57	26.93		NOX=94.4
8-Jul-05	12:48:10	0.04	94.25	94.55	0.86	26.65	26.74		NOX=94.4
8-Jul-05	12:48:15	0.00	94.25	94.55	0.85	26.61	26.70		NOX=94.4
8-Jul-05	12:48:20	0.04	94.78	95.53	0.89	26.81	27.03		NOX=94.4
8-Jul-05	12:48:25	0.08	94.78	95.53	0.88	26.86	27.07		NOX=94.4
8-Jul-05	12:48:30	0.00	94.77	95.53	0.86	26.75	26.97		NOX=94.4
8-Jul-05	12:48:35	0.02	94.77	95.63	0.86	26.78	27.03		NOX=94.4
8-Jul-05	12:48:40	-0.02	94.78	95.53	0.86	26.73	26.94		NOX=94.4
8-Jul-05	12:48:45	0.08	94.78	95.53	0.87	26.86	27.07		NOX=94.4
8-Jul-05	12:48:50	0.04	94.78	95.53	0.88	26.81	27.02		NOX=94.4
8-Jul-05	12:48:55	0.01	94.83	95.53	0.85	26.78	26.98		NOX=94.4
8-Jul-05	12:49:00	0.05	94.83	95.63	0.88	26.84	27.07		NOX=94.4
8-Jul-05	12:49:05	0.01	94.83	95.53	0.88	26.78	26.98		NOX=94.4
8-Jul-05	12:49:10	0.05	94.84	94.45	0.88	26.83	26.72		NOX=94.4
8-Jul-05	12:49:15	0.01	94.83	94.55	0.85	26.78	26.70		NOX=94.4
8-Jul-05	12:49:20	0.04	94.83	94.55	0.88	26.82	26.74		NOX=94.4
8-Jul-05	12:49:25	0.02	94.83	94.55	0.86	26.79	26.71		NOX=94.4
8-Jul-05	12:49:30	0.04	94.88	94.45	0.89	26.84	26.72		NOX=94.4
8-Jul-05	12:49:35	-0.03	94.89	94.55	0.86	26.75	26.65		NOX=94.4
8-Jul-05	12:49:40	0.00	94.88	94.55	0.86	26.79	26.69		NOX=94.4
8-Jul-05	12:49:45	0.09	94.88	94.55	0.87	26.90	26.80		NOX=94.4
8-Jul-05	12:49:50	0.02	94.89	94.55	0.85	26.81	26.72		NOX=94.4
8-Jul-05	12:49:55	0.09	94.88	94.55	0.87	26.90	26.80		NOX=94.4
8-Jul-05	12:50:00	0.06	94.88	95.53	0.88	26.86	27.04		NOX=94.4
8-Jul-05	12:50:05	-0.03	94.89	95.53	0.86	26.75	26.93		NOX=94.4
8-Jul-05	12:50:10	0.01	94.84	95.53	0.86	26.79	26.98		NOX=94.4
8-Jul-05	12:50:15	0.01	94.84	95.53	0.86	26.78	26.98		NOX=94.4
8-Jul-05	12:50:20	0.03	94.83	95.43	0.85	26.81	26.99		NOX=94.4
8-Jul-05	12:50:25	0.04	94.84	95.53	0.89	26.82	27.02		NOX=94.4
8-Jul-05	12:50:30	0.01	94.84	95.53	0.85	26.78	26.98		NOX=94.4
8-Jul-05	12:50:35	0.01	94.88	95.53	0.89	26.80	26.98		NOX=94.4
8-Jul-05	12:50:40	0.01	94.88	96.52	0.85	26.80	27.26		NOX=94.4
8-Jul-05	12:50:45	0.01	94.88	96.61	0.85	26.80	27.29		NOX=94.4
8-Jul-05	12:50:50	0.02	94.89	95.53	0.86	26.81	26.99		NOX=94.4
8-Jul-05	12:50:55	0.04	94.89	95.53	0.88	26.85	27.03		NOX=94.4
8-Jul-05	12:53:49	0.08	110.00	297.71	0.87	31.17	84.37		CO=306
8-Jul-05	12:53:54	-0.02	110.00	293.68	0.85	31.02	82.82		CO=306
8-Jul-05	12:53:59	0.08	110.00	294.66	0.85	31.17	83.50		CO=306
8-Jul-05	12:54:04	-0.02	110.00	294.66	0.85	31.02	83.08		CO=306
8-Jul-05	12:54:09	0.01	110.00	294.66	0.85	31.06	83.21		CO=306
8-Jul-05	12:54:14	0.01	110.00	294.66	0.89	31.07	83.22		CO=306
8-Jul-05	12:54:19	0.03	110.00	296.72	0.87	31.10	83.90		CO=306
8-Jul-05	12:54:24	0.02	110.00	296.72	0.85	31.08	83.83		CO=306
8-Jul-05	12:54:29	0.05	110.00	295.74	0.89	31.12	83.67		CO=306

Source Testing And Consulting Services, Inc.

Scrubber B - Power Boiler 3

8-Jul-05		RAYONIER	Fuel:	Bark				Unit #	SCRUBBER B
	Parameter	O2	NOx	CO	CO2	NOx	CO	0.00	0.00 Comments
	Units	%V	ppmV	ppmV	%	@15%O2	@15%O2	0.00	0.00
8-Jul-05	12:57:30	12.52	0.62	0.49	0.88	0.44	0.35		O2=12.53
8-Jul-05	12:57:35	12.53	0.61	0.39	0.87	0.43	0.28		O2=12.53
8-Jul-05	12:57:40	12.51	0.62	0.49	0.89	0.44	0.35		O2=12.53
8-Jul-05	12:57:45	12.46	0.61	0.29	0.89	0.43	0.21		O2=12.53
8-Jul-05	12:57:50	12.55	0.62	0.39	0.88	0.44	0.28		O2=12.53
8-Jul-05	12:57:55	12.45	0.62	0.49	0.85	0.43	0.34		O2=12.53
8-Jul-05	12:58:48	19.87	0.96	1.38	0.86	5.49	7.85		O2=20
8-Jul-05	12:58:53	19.95	1.03	1.38	0.85	6.42	8.56		O2=20
8-Jul-05	12:58:58	19.93	1.02	1.38	0.88	6.22	8.37		O2=20
8-Jul-05	12:59:03	19.87	1.03	1.38	0.89	5.92	7.89		O2=20
8-Jul-05	12:59:08	19.95	1.03	0.39	0.88	6.39	2.43		O2=20

Source Testing And Consulting Services, Inc.

Scrubber B - Power Boiler 3

8-Jul-05 RAYONIER Fuel: oil/bark Unit # SCRUBBER B

	Parameter	O2	NOx	CO	CO2	NOx	CO	0.00	0.00	Comments	
	Units	%V	ppmV	ppmV	%	@15%O2	@15%O2	0.00	0.00		
8-Jul-05	13:49:12	0.03	45.36	45.50	0.85	12.82	12.86			NOX=44.6 CO=48.3	SCRUBBER B
8-Jul-05	13:49:17	0.07	45.35	45.60	0.89	12.85	12.92			NOX=44.6 CO=48.3	PRE OIL TESTS
8-Jul-05	13:49:22	0.05	45.41	45.60	0.86	12.85	12.90			NOX=44.6 CO=48.3	
8-Jul-05	13:49:27	0.03	45.41	46.58	0.86	12.84	13.17			NOX=44.6 CO=48.3	
8-Jul-05	13:49:32	0.09	45.41	46.49	0.88	12.87	13.18			NOX=44.6 CO=48.3	
8-Jul-05	13:49:37	0.06	45.46	46.49	0.89	12.87	13.16			NOX=44.6 CO=48.3	
8-Jul-05	13:49:42	0.07	45.46	46.58	0.89	12.88	13.20			NOX=44.6 CO=48.3	
8-Jul-05	13:52:58	0.01	94.42	97.38	0.88	26.66	27.50			NOX=94.4 CO=96.8	
8-Jul-05	13:53:04	0.07	94.53	96.37	0.88	26.78	27.30			NOX=94.4 CO=96.8	
8-Jul-05	13:53:09	0.02	94.53	96.27	0.85	26.71	27.20			NOX=94.4 CO=96.8	
8-Jul-05	13:53:14	0.06	94.59	96.37	0.85	26.78	27.28			NOX=94.4 CO=96.8	
8-Jul-05	13:53:19	0.03	94.59	96.37	0.88	26.74	27.24			NOX=94.4 CO=96.8	
8-Jul-05	13:54:00	12.49	94.41	69.54	0.87	66.56	49.03			O2=12.53	
8-Jul-05	13:54:06	12.49	94.42	69.54	0.89	66.26	48.80			O2=12.53	
8-Jul-05	13:54:11	12.61	66.39	39.68	0.88	47.24	28.23			O2=12.53	
8-Jul-05	13:54:16	12.53	66.39	16.91	0.85	46.81	11.92			O2=12.53	
8-Jul-05	13:54:21	12.59	66.39	17.01	0.88	47.13	12.07			O2=12.53	
8-Jul-05	13:54:26	12.55	66.40	5.67	0.85	46.94	4.01			O2=12.53	
8-Jul-05	13:54:31	12.55	66.39	5.57	0.86	46.93	3.94			O2=12.53	
8-Jul-05	13:54:36	12.64	20.26	1.42	0.88	14.47	1.01			O2=12.53	
8-Jul-05	13:54:41	12.62	20.26	1.42	0.86	14.43	1.01			O2=12.53	
8-Jul-05	13:55:29	20.07	0.90	1.42	0.87	6.41	10.05			O2=20	
8-Jul-05	13:55:34	20.09	0.86	0.40	0.85	6.24	2.96			O2=20	
8-Jul-05	13:55:39	20.13	0.85	0.40	0.89	6.47	3.10			O2=20	
8-Jul-05	13:55:44	20.17	0.85	0.40	0.87	6.84	3.28			O2=20	
8-Jul-05	13:55:49	20.10	0.56	0.40	0.85	4.12	2.98			O2=20	
8-Jul-05	13:58:33	12.99	63.28	30.37	7.14	47.18	22.64			SCRUBBER B OIL RUN 1	START
8-Jul-05	13:59:33	13.16	63.58	32.39	7.19	48.48	24.70			SCRUBBER B OIL RUN 1	
8-Jul-05	14:00:33	13.31	63.81	31.38	7.12	49.59	24.39			SCRUBBER B OIL RUN 1	
8-Jul-05	14:01:33	13.52	63.52	30.37	6.89	50.78	24.28			SCRUBBER B OIL RUN 1	
8-Jul-05	14:02:33	13.34	62.70	31.48	7.03	48.90	24.55			SCRUBBER B OIL RUN 1	
8-Jul-05	14:03:33	12.87	63.16	31.38	7.41	46.42	23.06			SCRUBBER B OIL RUN 1	
8-Jul-05	14:04:33	12.60	63.81	38.52	7.59	45.35	27.37			SCRUBBER B OIL RUN 1	
8-Jul-05	14:05:33	12.55	63.99	42.67	7.63	45.22	30.15			SCRUBBER B OIL RUN 1	
8-Jul-05	14:06:33	12.61	63.40	39.63	7.63	45.12	28.21			SCRUBBER B OIL RUN 1	
8-Jul-05	14:07:33	12.84	63.23	40.64	7.55	46.26	29.74			SCRUBBER B OIL RUN 1	
8-Jul-05	14:08:33	13.14	62.82	35.48	7.24	47.75	26.97			SCRUBBER B OIL RUN 1	
8-Jul-05	14:09:33	13.06	61.29	35.48	7.26	46.10	26.68			SCRUBBER B OIL RUN 1	
8-Jul-05	14:10:33	12.84	61.75	38.62	7.51	45.21	28.27			SCRUBBER B OIL RUN 1	
8-Jul-05	14:11:33	12.59	61.93	38.62	7.62	43.95	27.41			SCRUBBER B OIL RUN 1	
8-Jul-05	14:12:33	12.47	63.57	43.68	7.70	44.48	30.56			SCRUBBER B OIL RUN 1	
8-Jul-05	14:13:33	12.30	63.34	40.64	7.89	43.44	27.88			SCRUBBER B OIL RUN 1	
8-Jul-05	14:14:33	12.26	62.99	41.66	7.90	43.01	28.44			SCRUBBER B OIL RUN 1	
8-Jul-05	14:15:33	12.12	62.81	46.82	7.93	42.22	31.48			SCRUBBER B OIL RUN 1	
8-Jul-05	14:16:33	11.89	63.11	48.94	8.22	41.31	32.03			SCRUBBER B OIL RUN 1	
8-Jul-05	14:17:33	11.70	62.99	52.99	8.28	40.39	33.98			SCRUBBER B OIL RUN 1	
8-Jul-05	14:18:33	12.15	63.69	41.66	7.98	42.94	28.08			SCRUBBER B OIL RUN 1	
8-Jul-05	14:19:33	12.03	64.57	38.62	8.07	42.93	25.68			SCRUBBER B OIL RUN 1	
8-Jul-05	14:20:33	12.00	65.11	38.62	8.03	43.17	25.60			SCRUBBER B OIL RUN 1	
8-Jul-05	14:21:33	12.16	64.92	35.38	7.98	43.83	23.89			SCRUBBER B OIL RUN 1	
8-Jul-05	14:22:33	12.07	64.40	35.48	8.03	43.01	23.69			SCRUBBER B OIL RUN 1	
8-Jul-05	14:23:33	12.05	65.80	36.49	8.01	43.85	24.32			SCRUBBER B OIL RUN 1	
8-Jul-05	14:24:33	11.90	66.86	38.62	8.10	43.82	25.31			SCRUBBER B OIL RUN 1	
8-Jul-05	14:25:33	11.75	67.21	37.51	8.25	43.36	24.20			SCRUBBER B OIL RUN 1	
8-Jul-05	14:26:33	11.86	67.55	36.49	8.24	44.08	23.81			SCRUBBER B OIL RUN 1	
8-Jul-05	14:27:33	11.84	67.33	34.47	8.16	43.85	22.45			SCRUBBER B OIL RUN 1	
8-Jul-05	14:28:33	11.80	68.38	36.39	8.21	44.34	23.60			SCRUBBER B OIL RUN 1	
8-Jul-05	14:29:33	11.85	67.80	39.53	8.17	44.19	25.76			SCRUBBER B OIL RUN 1	
8-Jul-05	14:30:33	11.86	66.97	40.64	8.17	43.71	26.53			SCRUBBER B OIL RUN 1	
8-Jul-05	14:31:33	11.79	66.91	37.51	8.21	43.33	24.29			SCRUBBER B OIL RUN 1	
8-Jul-05	14:32:33	11.29	67.33	40.64	8.48	41.33	24.95			SCRUBBER B OIL RUN 1	
8-Jul-05	14:33:33	11.21	68.44	42.67	8.65	41.65	25.97			SCRUBBER B OIL RUN 1	

Source Testing And Consulting Services, Inc.

Scrubber B - Power Boiler 3

8-Jul-05		RAYONIER		Fuel:	oil/bark			Unit #	SCRUBBER B	
	Parameter	O2	NOx	CO	CO2	NOx	CO	0.00	0.00	Comments
	Units	%V	ppmV	ppmV	%	@15%O2	@15%O2	0.00	0.00	
8-Jul-05	14:34:33	10.95	67.74	55.12	8.83	40.18	32.69			SCRUBBER B OIL RUN 1
8-Jul-05	14:35:33	10.74	68.32	64.33	9.03	39.66	37.35			SCRUBBER B OIL RUN 1
8-Jul-05	14:36:33	10.85	68.85	77.79	8.97	40.42	45.67			SCRUBBER B OIL RUN 1
8-Jul-05	14:37:33	11.34	69.19	60.18	8.60	42.72	37.16			SCRUBBER B OIL RUN 1
8-Jul-05	14:38:33	10.86	68.71	78.81	8.97	40.36	46.29			SCRUBBER B OIL RUN 1
8-Jul-05	14:39:33	10.59	67.86	88.12	9.11	38.85	50.45			SCRUBBER B OIL RUN 1
8-Jul-05	14:40:33	10.58	67.67	89.13	9.18	38.69	50.96			SCRUBBER B OIL RUN 1
8-Jul-05	14:41:33	10.81	67.38	97.23	8.92	39.41	56.87			SCRUBBER B OIL RUN 1
8-Jul-05	14:42:33	10.85	66.68	92.17	8.98	39.14	54.11			SCRUBBER B OIL RUN 1
8-Jul-05	14:43:33	11.16	66.86	71.52	8.76	40.50	43.32			SCRUBBER B OIL RUN 1
8-Jul-05	14:44:33	11.94	66.91	51.88	8.16	44.08	34.18			SCRUBBER B OIL RUN 1
8-Jul-05	14:45:33	12.89	66.04	39.63	7.51	48.62	29.18			SCRUBBER B OIL RUN 1
8-Jul-05	14:46:33	12.81	64.87	30.32	7.48	47.29	22.10			SCRUBBER B OIL RUN 1
8-Jul-05	14:47:33	12.49	62.81	35.48	7.79	44.06	24.89			SCRUBBER B OIL RUN 1
8-Jul-05	14:48:33	12.52	62.82	36.49	7.74	44.21	25.68			SCRUBBER B OIL RUN 1
8-Jul-05	14:49:33	12.44	63.05	34.47	7.74	43.95	24.03			SCRUBBER B OIL RUN 1
8-Jul-05	14:50:33	12.25	62.92	34.47	7.94	42.90	23.50			SCRUBBER B OIL RUN 1
8-Jul-05	14:51:33	12.37	63.05	34.47	7.89	43.60	23.83			SCRUBBER B OIL RUN 1
8-Jul-05	14:52:33	12.40	64.10	33.46	7.81	44.50	23.23			SCRUBBER B OIL RUN 1
8-Jul-05	14:53:33	12.05	65.04	33.46	7.91	43.35	22.30			SCRUBBER B OIL RUN 1
8-Jul-05	14:54:33	12.17	65.69	38.52	8.05	44.41	26.04			SCRUBBER B OIL RUN 1
8-Jul-05	14:55:33	12.12	65.74	39.53	7.91	44.20	26.58			SCRUBBER B OIL RUN 1
8-Jul-05	14:56:33	12.14	65.10	36.49	8.03	43.84	24.58			SCRUBBER B OIL RUN 1
8-Jul-05	14:57:33	12.32	65.27	35.38	7.78	44.89	24.33			SCRUBBER B OIL RUN 1
8-Jul-05	14:58:33	12.32	65.69	35.48	7.78	44.89	24.33			SCRUBBER B OIL RUN 1
8-Jul-05	15:00:27	20.15	0.60	0.46	0.89	4.73	3.57			O2=20
8-Jul-05	15:00:32	20.12	0.55	0.35	0.85	4.13	2.69			O2=20
8-Jul-05	15:00:37	20.17	0.55	0.46	0.86	4.41	3.69			O2=20
8-Jul-05	15:00:42	20.11	0.55	0.35	0.85	4.10	2.66			O2=20
8-Jul-05	15:01:45	12.60	0.50	1.37	0.85	0.35	0.97			O2=12.53
8-Jul-05	15:01:50	12.69	0.50	0.35	0.88	0.36	0.25			O2=12.53
8-Jul-05	15:01:55	12.69	0.50	0.35	0.87	0.36	0.25			O2=12.53
8-Jul-05	15:02:00	12.65	0.50	0.35	0.88	0.35	0.25			O2=12.53
8-Jul-05	15:02:05	12.66	0.49	0.35	0.89	0.35	0.25			O2=12.53
8-Jul-05	15:04:06	0.11	94.47	95.48	0.88	26.81	27.10			NO=94.4 CO=96.8
8-Jul-05	15:04:12	0.00	94.41	94.50	0.88	26.65	26.68			NO=94.4 CO=96.8
8-Jul-05	15:04:17	0.02	94.35	94.50	0.86	26.66	26.70			NO=94.4 CO=96.8
8-Jul-05	15:04:22	0.11	94.35	94.50	0.84	26.78	26.82			NO=94.4 CO=96.8
8-Jul-05	15:04:27	0.00	94.35	97.33	0.85	26.64	27.48			NO=94.4 CO=96.8
8-Jul-05	15:04:32	0.06	94.35	96.22	0.85	26.72	27.24			NO=94.4 CO=96.8
8-Jul-05	15:04:37	0.08	94.53	96.32	0.88	26.78	27.29			NO=94.4 CO=96.8
8-Jul-05	15:08:34	11.92	64.75	45.81	8.12	42.56	30.10			RUN 2
8-Jul-05	15:09:34	11.98	65.39	41.66	8.00	43.26	27.56			RUN 2
8-Jul-05	15:10:34	11.45	66.86	46.82	8.50	41.73	29.23			RUN 2
8-Jul-05	15:11:34	11.43	68.51	55.12	8.45	42.69	34.34			RUN 2
8-Jul-05	15:12:34	11.22	69.84	49.96	8.53	42.56	30.44			RUN 2
8-Jul-05	15:13:34	11.24	70.08	61.29	8.57	42.80	37.43			RUN 2
8-Jul-05	15:14:34	11.14	69.96	63.42	8.66	42.31	38.35			RUN 2
8-Jul-05	15:15:34	10.98	68.91	76.68	8.80	40.98	45.60			RUN 2
8-Jul-05	15:16:34	11.27	67.92	66.46	8.60	41.60	40.70			RUN 2
8-Jul-05	15:17:34	11.18	67.56	66.46	8.64	41.01	40.34			RUN 2
8-Jul-05	15:18:34	11.39	67.09	58.26	8.54	41.61	36.13			RUN 2
8-Jul-05	15:19:34	11.55	66.86	52.99	8.41	42.19	33.45			RUN 2
8-Jul-05	15:20:34	11.40	65.57	52.99	8.43	40.74	32.93			RUN 2
8-Jul-05	15:21:34	11.70	65.69	50.97	8.36	42.12	32.68			RUN 2
8-Jul-05	15:22:34	11.96	65.74	47.83	8.14	43.37	31.56			RUN 2
8-Jul-05	15:23:34	11.80	66.28	40.54	8.14	42.99	26.30			RUN 2
8-Jul-05	15:24:34	12.00	67.15	43.78	8.11	44.51	29.02			RUN 2
8-Jul-05	15:25:34	11.39	66.57	50.06	8.32	41.29	31.05			RUN 2
8-Jul-05	15:26:34	11.54	68.16	47.93	8.36	42.97	30.22			RUN 2
8-Jul-05	15:27:34	11.23	67.16	45.90	8.52	40.99	28.02			RUN 2
8-Jul-05	15:28:34	11.34	68.34	46.92	8.56	42.16	28.94			RUN 2
8-Jul-05	15:29:34	11.31	68.80	49.04	8.48	42.32	30.17			RUN 2

Source Testing And Consulting Services, Inc.

Scrubber B - Power Boiler 3

8-Jul-05 RAYONIER Fuel: oil/bark Unit # SCRUBBER B

	Parameter	O2	NOx	CO	CO2	NOx	CO	0.00	0.00	Comments
	Units	%V	ppmV	ppmV	%	@15%O2	@15%O2	0.00	0.00	
8-Jul-05	15:30:34	11.24	69.03	51.07	8.56	42.14	31.18			RUN 2
8-Jul-05	15:31:34	11.79	68.33	44.79	8.21	44.23	29.00			RUN 2
8-Jul-05	15:32:34	12.19	66.33	35.58	7.93	44.91	24.09			RUN 2
8-Jul-05	15:33:34	12.27	65.93	37.60	7.90	45.07	25.71			RUN 2
8-Jul-05	15:34:34	12.42	65.63	29.41	7.76	45.65	20.45			RUN 2
8-Jul-05	15:35:34	12.70	63.93	33.56	7.60	45.98	24.14			RUN 2
8-Jul-05	15:36:34	12.81	63.28	26.27	7.43	46.17	19.16			RUN 2
8-Jul-05	15:37:34	13.12	62.41	26.27	7.30	47.34	19.93			RUN 2
8-Jul-05	15:38:34	13.18	62.12	24.24	7.22	47.49	18.53			RUN 2
8-Jul-05	15:39:34	13.26	61.58	23.13	7.13	47.54	17.86			RUN 2
8-Jul-05	15:40:34	13.22	60.83	23.23	7.18	46.73	17.85			RUN 2
8-Jul-05	15:41:34	13.42	61.42	22.22	7.06	48.47	17.54			RUN 2
8-Jul-05	15:42:34	13.37	62.12	21.21	7.03	48.69	16.62			RUN 2
8-Jul-05	15:43:34	13.26	62.59	19.08	7.11	48.35	14.74			RUN 2
8-Jul-05	15:44:34	13.20	63.57	20.04	7.11	48.71	15.36			RUN 2
8-Jul-05	15:45:34	13.20	64.22	19.03	7.19	49.22	14.59			RUN 2
8-Jul-05	15:46:34	13.05	64.98	20.04	7.27	48.85	15.07			RUN 2
8-Jul-05	15:47:34	12.88	65.10	21.05	7.43	47.88	15.48			RUN 2
8-Jul-05	15:48:34	12.68	65.27	22.17	7.54	46.86	15.91			RUN 2
8-Jul-05	15:49:34	12.44	65.74	22.07	7.75	45.84	15.39			RUN 2
8-Jul-05	15:50:34	12.21	66.85	24.19	7.88	45.39	16.42			RUN 2
8-Jul-05	15:51:34	12.27	67.22	26.22	7.88	45.94	17.92			RUN 2
8-Jul-05	15:52:34	12.10	67.21	28.34	7.98	45.07	19.01			RUN 2
8-Jul-05	15:53:34	11.91	66.51	31.38	8.14	43.65	20.59			RUN 2
8-Jul-05	15:54:34	12.09	66.16	33.50	7.97	44.32	22.44			RUN 2
8-Jul-05	15:55:34	11.97	65.51	36.54	7.98	43.30	24.15			RUN 2
8-Jul-05	15:56:34	11.79	65.22	34.41	8.02	42.25	22.29			RUN 2
8-Jul-05	15:57:34	12.25	40.83	31.38	7.99	27.84	21.39			RUN 2
8-Jul-05	15:58:34	12.25	41.83	31.38	7.97	27.84	21.39			RUN 2
8-Jul-05	15:59:34	11.84	64.81	37.55	8.02	42.22	24.47			RUN 2
8-Jul-05	16:00:34	11.84	64.81	37.55	8.00	42.22	24.47			RUN 2
8-Jul-05	16:01:34	11.84	64.81	37.55	7.97	42.22	24.47			RUN 2
8-Jul-05	16:02:34	11.37	64.75	46.86	7.98	40.10	29.02			RUN 2
8-Jul-05	16:03:34	11.74	66.51	42.82	7.98	70.88	27.59			RUN 2
8-Jul-05	16:04:34	11.93	66.51	32.30	8.22	43.73	21.23			RUN 2
8-Jul-05	16:05:34	12.04	66.69	32.40	8.39	44.41	21.57			RUN 2
8-Jul-05	16:06:34	12.38	66.22	29.26	8.34	45.87	20.27			RUN 2
8-Jul-05	16:07:34	11.81	65.58	33.41	8.18	42.56	21.68			RUN 2
8-Jul-05	16:08:34	11.58	65.58	39.48	7.89	60.81	25.01			RUN 2
8-Jul-05	16:15:07	0.07	94.18	96.08	7.41	26.68	27.22			NOX=94.4 CO=96.8
8-Jul-05	16:15:12	0.11	94.12	97.12	5.07	26.71	27.56			NOX=94.4 CO=96.8
8-Jul-05	16:15:17	0.05	94.13	97.01	4.50	26.63	27.45			NOX=94.4 CO=96.8
8-Jul-05	16:15:22	0.03	94.13	97.12	3.93	26.61	27.46			NOX=94.4 CO=96.8
8-Jul-05	16:15:27	0.04	94.12	97.12	3.43	26.62	27.47			NOX=94.4 CO=96.8
8-Jul-05	16:16:42	12.51	55.48	9.80	1.29	39.00	6.89			02=12.53
8-Jul-05	16:16:48	12.53	8.76	2.48	1.23	6.17	1.75			02=12.53
8-Jul-05	16:16:53	12.59	8.76	0.31	1.22	6.22	0.22			02=12.53
8-Jul-05	16:16:58	12.57	8.76	0.21	1.17	6.20	0.15			02=12.53
8-Jul-05	16:17:03	12.57	0.96	0.31	1.18	0.68	0.22			02=12.53
8-Jul-05	16:17:08	12.57	0.95	0.41	1.17	0.68	0.29			02=12.53
8-Jul-05	16:17:13	12.54	0.67	0.31	1.13	0.47	0.22			02=12.53
8-Jul-05	16:17:18	12.53	0.67	0.31	1.13	0.47	0.22			02=12.53
8-Jul-05	16:17:23	12.60	0.66	0.31	1.11	0.47	0.22			02=12.53
8-Jul-05	16:17:28	12.59	0.55	0.31	1.11	0.39	0.22			02=12.53
8-Jul-05	16:17:33	12.65	0.55	0.21	1.13	0.39	0.15			02=12.53
8-Jul-05	16:19:19	20.12	0.55	0.41	1.03	4.14	3.11			O2=20
8-Jul-05	16:19:24	20.07	0.54	0.21	0.99	3.83	1.46			O2=20
8-Jul-05	16:19:29	20.12	0.55	0.31	1.02	4.17	2.35			O2=20
8-Jul-05	16:19:34	20.14	0.55	0.41	0.98	4.28	3.21			O2=20
8-Jul-05	16:19:39	20.13	0.55	0.41	1.02	4.20	3.15			O2=20
8-Jul-05	16:19:44	20.16	0.55	0.41	1.01	4.39	3.29			O2=20
8-Jul-05	16:19:49	20.05	0.37	0.41	0.99	2.60	2.87			O2=20

Source Testing And Consulting Services, Inc. IDLE

7/14/2005 RAYONIER Fuel: Bark & Oil Unit # SCRUBBER B

	Parameter	O2	NOx	CO	CO2	NOx	CO	0	0	Comments
	Units	%V	ppmV	ppmV	%	@3%O2	@3%O2	0	0	
14-Jul-05	7:54:36	-0.01	93.71	98.20	0.92	26.44	27.71			CE NOX=92.9 CO=96\
14-Jul-05	7:54:42	-0.01	93.66	98.10	0.21	26.42	27.68			CE NOX=92.9 CO=96\
14-Jul-05	7:54:47	0.03	93.71	98.20	0.20	26.49	27.76			CE NOX=92.9 CO=96\
14-Jul-05	7:54:52	-0.01	93.71	98.20	0.94	26.45	27.71			CE NOX=92.9 CO=96\
14-Jul-05	7:54:57	0.01	93.71	99.23	0.99	26.47	28.03			CE NOX=92.9 CO=96\
14-Jul-05	7:55:02	0.03	93.71	99.33	0.90	26.49	28.08			CE NOX=92.9 CO=96\
14-Jul-05	7:55:07	0.03	93.71	98.20	0.08	26.49	27.76			CE NOX=92.9 CO=96\
14-Jul-05	7:55:12	-0.01	93.71	98.20	0.91	26.44	27.71			CE NOX=92.9 CO=96\
14-Jul-05	7:55:17	0.03	93.13	97.17	0.34	26.33	27.47			CE NOX=92.9 CO=96\
14-Jul-05	7:55:26	0.03	93.12	97.17	0.41	26.32	27.47			LB
14-Jul-05	7:55:31	0.00	93.12	97.17	0.86	26.29	27.43			LB
14-Jul-05	7:55:36	0.02	93.12	97.17	0.12	26.32	27.46			LB
14-Jul-05	7:55:41	0.00	93.12	97.17	0.00	26.29	27.43			LB
14-Jul-05	7:55:46	0.00	93.18	97.17	0.80	26.30	27.43			LB
14-Jul-05	7:55:51	0.01	93.19	97.06	0.91	26.32	27.42			LB
14-Jul-05	8:01:48	0.03	48.64	47.73	7.24	13.75	13.49			CE NOX=48.2 CO=47.9
14-Jul-05	8:01:53	0.02	48.63	47.73	6.92	13.74	13.49			CE NOX=48.2 CO=47.9
14-Jul-05	8:01:58	0.02	48.63	47.73	7.17	13.74	13.49			CE NOX=48.2 CO=47.9
14-Jul-05	8:02:03	0.01	48.63	47.73	7.13	13.74	13.48			CE NOX=48.2 CO=47.9
14-Jul-05	8:02:08	0.01	48.63	47.73	6.85	13.73	13.48			CE NOX=48.2 CO=47.9
14-Jul-05	8:02:13	-0.01	48.63	47.73	6.85	13.72	13.47			CE NOX=48.2 CO=47.9
14-Jul-05	8:02:18	0.02	48.63	47.84	6.93	13.74	13.52			CE NOX=48.2 CO=47.9
14-Jul-05	8:02:23	0.01	48.63	47.84	7.13	13.73	13.51			CE NOX=48.2 CO=47.9
14-Jul-05	8:02:27	0.03	48.63	47.73	7.09	13.75	13.49			LB
14-Jul-05	8:02:32	0.03	48.63	47.73	6.89	13.74	13.49			LB
14-Jul-05	8:02:37	0.01	48.63	47.73	7.28	13.73	13.48			LB
14-Jul-05	8:02:42	-0.01	48.64	47.73	6.87	13.72	13.47			LB
14-Jul-05	8:02:47	0.02	48.63	47.84	6.83	13.74	13.51			LB
14-Jul-05	8:02:52	-0.01	48.57	47.73	6.68	13.71	13.47			LB
14-Jul-05	8:07:41	20.01	0.32	0.46	7.07	2.12	3.08			CE O2=20.00
14-Jul-05	8:07:46	20.04	0.31	0.26	7.57	2.12	1.77			CE O2=20.00
14-Jul-05	8:07:51	19.99	0.32	0.26	7.13	2.07	1.67			CE O2=20.00
14-Jul-05	8:07:56	19.99	0.32	0.52	7.21	2.11	3.35			CE O2=20.00
14-Jul-05	8:08:01	19.98	0.32	0.52	7.21	2.08	3.30			CE O2=20.00
14-Jul-05	8:08:06	20.05	0.32	0.52	7.46	2.26	3.60			CE O2=20.00
14-Jul-05	8:08:11	19.95	0.32	0.52	7.51	2.02	3.21			LB
14-Jul-05	8:08:16	20.04	0.32	0.41	7.21	2.22	2.82			LB
14-Jul-05	8:08:21	20.04	0.32	0.41	6.75	2.22	2.83			LB
14-Jul-05	8:08:26	19.96	0.32	0.52	7.16	2.03	3.22			LB
14-Jul-05	8:08:31	19.99	0.31	0.52	6.78	2.04	3.35			LB
14-Jul-05	8:08:36	20.02	0.32	0.41	7.47	2.18	2.77			LB
14-Jul-05	8:09:43	12.58	0.31	0.41	7.17	0.22	0.29			CE O2=12.53
14-Jul-05	8:09:48	12.50	0.38	0.31	7.19	0.27	0.22			CE O2=12.53
14-Jul-05	8:09:53	12.56	0.38	0.41	7.02	0.27	0.29			CE O2=12.53
14-Jul-05	8:09:58	12.57	0.38	0.52	6.95	0.27	0.37			CE O2=12.53
14-Jul-05	8:10:03	12.51	0.38	0.41	7.03	0.27	0.29			CE O2=12.53
14-Jul-05	8:10:08	12.54	0.38	0.41	7.38	0.27	0.29			CE O2=12.53
14-Jul-05	8:10:13	12.49	0.38	0.52	7.17	0.27	0.36			CE O2=12.53
14-Jul-05	8:10:18	12.56	0.38	0.52	7.35	0.27	0.36			CE O2=12.53
14-Jul-05	8:10:25	12.52	0.32	0.52	7.24	0.23	0.36			LB
14-Jul-05	8:10:30	12.54	0.32	0.52	7.33	0.23	0.36			LB
14-Jul-05	8:10:35	12.50	0.32	0.41	6.92	0.23	0.29			LB
14-Jul-05	8:10:40	12.55	0.32	0.52	7.38	0.23	0.36			LB
14-Jul-05	8:10:45	12.58	0.32	0.52	7.18	0.23	0.37			LB
14-Jul-05	8:10:50	12.47	0.32	0.41	6.94	0.23	0.29			LB
14-Jul-05	8:10:55	12.58	0.32	0.52	7.00	0.23	0.37			LB
14-Jul-05	8:11:00	12.50	0.32	0.52	6.87	0.23	0.36			LB
14-Jul-05	8:15:21	0.10	110.00	891.99	7.00	31.20	253.00			CE CO=905
14-Jul-05	8:15:26	0.08	110.00	895.01	7.20	31.17	250.81			CE CO=905
14-Jul-05	8:15:31	-0.01	110.00	895.01	7.01	31.04	249.75			CE CO=905

Source Testing And Consulting Services, Inc. IDLE

7/14/2005		RAYONIER		Fuel:	Bark & Oil			Unit #	SCRUBBER B
	Parameter	O2	NOx	CO	CO2	NOx	CO	0	0 Comments
	Units	%V	ppmV	ppmV	%	@3%O2	@3%O2	0	0
14-Jul-05	8:15:36	0.08	110.00	898.94	7.37	31.17	251.89		CE CO=905
14-Jul-05	8:15:41	0.04	110.00	899.04	6.94	31.11	251.42		CE CO=905
14-Jul-05	8:15:46	0.07	110.00	892.02	7.28	31.16	244.15		CE CO=905
14-Jul-05	8:15:51	0.03	110.00	893.00	6.87	31.10	243.97		CE CO=905
14-Jul-05	8:15:56	0.06	110.00	896.98	7.28	31.15	251.16		CE CO=905
14-Jul-05	8:16:01	0.07	110.00	896.98	6.93	31.16	251.22		CE CO=905
14-Jul-05	8:16:06	0.06	110.00	912.03	7.32	31.14	261.59		CE CO=905
14-Jul-05	8:16:11	0.04	110.00	914.95	6.99	31.11	261.01		CE CO=905
14-Jul-05	8:16:19	0.08	110.00	918.06	7.00	31.18	267.86		LB
14-Jul-05	8:16:24	0.07	110.00	921.20	7.29	31.16	262.33		LB
14-Jul-05	8:16:29	0.00	110.00	916.00	7.03	31.05	261.41		LB
14-Jul-05	8:16:34	0.07	110.00	903.98	7.28	31.16	256.09		LB
14-Jul-05	8:16:39	0.07	110.00	903.98	7.33	31.15	256.00		LB
14-Jul-05	8:16:44	0.00	110.00	891.02	6.95	31.06	246.48		LB
14-Jul-05	8:16:49	0.02	110.00	891.02	7.14	31.09	246.71		LB
14-Jul-05	8:20:29	0.09	110.00	594.89	6.98	31.18	168.65		CE CO=619
14-Jul-05	8:20:34	-0.01	110.00	591.84	7.18	31.04	167.00		CE CO=619
14-Jul-05	8:20:39	0.02	110.00	591.94	6.97	31.08	167.24		CE CO=619
14-Jul-05	8:20:44	0.00	110.00	618.77	7.01	31.05	174.66		CE CO=619
14-Jul-05	8:20:49	0.03	110.00	618.87	7.01	31.10	174.95		CE CO=619
14-Jul-05	8:20:54	0.09	110.00	614.94	7.05	31.18	174.33		CE CO=619
14-Jul-05	8:20:59	0.02	110.00	614.84	7.00	31.09	173.75		LB
14-Jul-05	8:21:04	0.09	110.00	604.91	7.05	31.18	171.49		LB
14-Jul-05	8:21:09	0.09	110.00	604.91	7.33	31.19	171.51		LB
14-Jul-05	8:21:14	0.04	110.00	596.86	7.14	31.12	168.85		LB
14-Jul-05	8:21:19	0.02	110.00	596.76	6.95	31.09	168.64		LB
14-Jul-05	8:21:24	-0.02	110.00	600.88	7.02	31.02	169.47		LB
14-Jul-05	8:21:29	0.03	110.00	600.88	6.89	31.10	169.87		LB
14-Jul-05	8:21:34	0.04	110.00	601.97	7.18	31.11	170.27		LB
14-Jul-05	8:24:50	0.00	110.00	298.67	7.03	31.06	84.33		CE CO=306
14-Jul-05	8:24:55	0.01	110.00	297.69	6.99	31.07	84.08		CE CO=306
14-Jul-05	8:25:00	0.06	110.00	297.69	7.17	31.14	84.28		CE CO=306
14-Jul-05	8:25:05	0.09	110.00	303.78	6.80	31.19	86.14		CE CO=306
14-Jul-05	8:25:10	0.03	110.00	303.69	7.09	31.10	85.87		CE CO=306
14-Jul-05	8:25:15	0.01	110.00	300.74	6.74	31.07	84.94		CE CO=306
14-Jul-05	8:25:20	0.01	110.00	300.64	6.73	31.06	84.90		CE CO=306
14-Jul-05	8:25:26	0.04	110.00	298.77	6.81	31.11	84.49		LB
14-Jul-05	8:25:31	0.06	110.00	298.77	7.13	31.14	84.58		LB
14-Jul-05	8:25:36	-0.03	110.00	297.69	7.15	31.01	83.91		LB
14-Jul-05	8:25:41	0.03	110.00	297.69	6.87	31.09	84.15		LB
14-Jul-05	8:25:46	0.09	110.00	302.70	7.02	31.19	85.84		LB
14-Jul-05	8:25:51	-0.03	110.00	302.70	6.99	31.01	85.34		LB
14-Jul-05	8:35:38	12.40	0.50	0.34	9.00	0.34	0.24		CO2=9
14-Jul-05	8:35:43	12.44	0.50	0.44	9.01	0.35	0.31		CO2=9
14-Jul-05	8:35:48	12.47	0.44	0.44	9.01	0.31	0.31		CO2=9
14-Jul-05	8:35:53	12.40	0.44	0.44	9.01	0.30	0.31		CO2=9
14-Jul-05	8:35:58	12.44	0.44	0.25	9.00	0.31	0.17		CO2=9
14-Jul-05	8:36:03	12.47	0.43	0.44	9.00	0.30	0.31		CO2=9
14-Jul-05	8:36:08	12.42	0.43	0.44	8.99	0.30	0.31		CO2=9
14-Jul-05	8:36:13	12.45	0.44	0.34	9.03	0.31	0.24		CO2=9
14-Jul-05	8:36:18	12.42	0.44	0.34	9.03	0.30	0.24		CO2=9
14-Jul-05	8:36:23	12.39	0.44	0.34	9.00	0.30	0.24		CO2=9
14-Jul-05	8:36:28	12.35	0.43	0.34	9.01	0.30	0.24		CO2=9
14-Jul-05	8:36:33	12.35	0.43	0.44	9.01	0.30	0.31		CO2=9
14-Jul-05	8:36:38	12.36	0.43	0.44	8.99	0.30	0.31		CO2=9
14-Jul-05	8:36:43	12.39	0.44	0.44	8.99	0.30	0.31		CO2=9
14-Jul-05	8:36:48	12.40	0.43	0.44	9.02	0.30	0.31		CO2=9
14-Jul-05	8:36:53	12.39	0.43	0.34	8.99	0.30	0.24		CO2=9
14-Jul-05	8:37:04	12.47	0.43	0.34	9.02	0.30	0.24		LB
14-Jul-05	8:37:09	12.36	0.44	0.34	9.00	0.30	0.24		LB

Source Testing And Consulting Services, Inc. IDLE

7/14/2005 RAYONIER Fuel: Bark & Oil Unit # SCRUBBER B

	Parameter	O2	NOx	CO	CO2	NOx	CO	0	0 Comments	
	Units	%V	ppmV	ppmV	%	@3%O2	@3%O2	0	0	
14-Jul-05	8:37:14	12.43	0.44	0.34	9.03	0.30	0.24		LB	
14-Jul-05	8:37:19	12.42	0.43	0.34	8.96	0.30	0.24		LB	
14-Jul-05	8:37:51	12.39	0.43	0.34	17.98	0.30	0.24		CE CO2=18.1	
14-Jul-05	8:37:56	13.02	0.40	0.05	17.91	0.30	0.04		CE CO2=18.1	
14-Jul-05	8:38:01	12.29	0.44	0.34	18.00	0.30	0.24		CE CO2=18.1	
14-Jul-05	8:38:06	11.37	0.43	0.44	18.05	0.26	0.27		CE CO2=18.1	
14-Jul-05	8:38:15	12.25	0.43	0.44	17.99	0.29	0.30		LB	
14-Jul-05	8:38:20	12.39	0.44	0.44	18.05	0.30	0.31		LB	
14-Jul-05	8:38:25	11.72	0.40	0.15	17.73	0.26	0.09		LB	
14-Jul-05	8:38:30	13.45	0.39	-0.05	17.44	0.31	-0.04		LB	
14-Jul-05	8:38:35	11.68	0.44	0.44	18.06	0.28	0.28		LB	
14-Jul-05	8:38:40	10.84	0.44	0.34	17.98	0.26	0.20		LB	
14-Jul-05	8:38:45	11.78	0.34	-0.54	18.15	0.22	-0.35		LB	
14-Jul-05	8:59:45	12.22	77.47	49.43	7.71	159.72	101.91		SCRUBER B RUN1	BARK/OIL
14-Jul-05	9:00:45	12.36	78.47	49.53	7.51	164.42	103.79		SCRUBER B RUN1	
14-Jul-05	9:01:45	12.37	78.17	48.55	7.51	164.13	101.94		SCRUBER B RUN1	
14-Jul-05	9:02:45	12.18	75.24	46.58	7.65	154.47	95.63		SCRUBER B RUN1	
14-Jul-05	9:03:45	12.36	76.77	42.46	7.60	160.95	89.02		SCRUBER B RUN1	
14-Jul-05	9:04:45	12.55	75.42	39.51	7.41	161.76	84.74		SCRUBER B RUN1	
14-Jul-05	9:05:47	12.55	75.30	39.51	7.47	161.36	84.66		SCRUBER B RUN1	
14-Jul-05	9:06:47	12.33	75.95	46.49	7.60	158.56	97.05		SCRUBER B RUN1	
14-Jul-05	9:07:47	12.25	74.59	49.43	7.62	154.40	102.32		SCRUBER B RUN1	
14-Jul-05	9:08:47	12.41	73.65	46.49	7.51	155.24	98.00		SCRUBER B RUN1	
14-Jul-05	9:09:47	12.29	74.83	43.44	7.64	155.48	90.27		SCRUBER B RUN1	
14-Jul-05	9:10:47	12.23	75.88	48.36	7.69	156.72	99.88		SCRUBER B RUN1	
14-Jul-05	9:11:47	11.85	74.24	44.43	7.96	146.80	87.85		SCRUBER B RUN1	
14-Jul-05	9:12:47	12.20	75.36	58.48	7.65	155.03	120.31		SCRUBER B RUN1	
14-Jul-05	9:13:47	12.09	77.65	47.47	7.74	157.78	96.47		SCRUBER B RUN1	
14-Jul-05	9:14:47	12.49	76.47	41.38	7.50	162.79	88.09		SCRUBER B RUN1	
14-Jul-05	9:15:47	12.23	74.89	42.46	7.66	154.67	87.70		SCRUBER B RUN1	
14-Jul-05	9:16:47	12.44	74.82	41.38	7.55	158.25	87.53		SCRUBER B RUN1	
14-Jul-05	9:17:47	12.35	75.07	48.46	7.61	157.24	101.49		SCRUBER B RUN1	
14-Jul-05	9:18:48	12.17	74.77	44.43	7.68	153.38	91.14		SCRUBER B RUN1	
14-Jul-05	9:19:48	12.34	75.77	45.41	7.58	158.52	95.00		SCRUBER B RUN1	
14-Jul-05	9:20:48	12.30	75.54	41.48	7.70	157.17	86.31		SCRUBER B RUN1	
14-Jul-05	9:21:48	12.17	76.82	46.39	7.79	157.51	95.12		SCRUBER B RUN1	
14-Jul-05	9:22:48	12.30	76.53	55.44	7.69	159.33	115.41		SCRUBER B RUN1	
14-Jul-05	9:23:48	12.07	74.59	46.39	7.71	151.15	94.01		SCRUBER B RUN1	
14-Jul-05	9:24:48	12.14	75.77	49.44	7.70	154.83	101.02		SCRUBER B RUN1	
14-Jul-05	9:25:48	12.10	77.06	54.45	7.67	156.76	110.77		SCRUBER B RUN1	
14-Jul-05	9:26:48	12.10	75.42	51.41	7.68	153.46	104.60		SCRUBER B RUN1	
14-Jul-05	9:27:48	12.26	75.54	63.50	7.54	156.54	131.59		SCRUBER B RUN1	
14-Jul-05	9:28:48	12.17	76.25	47.57	7.71	156.28	97.50		SCRUBER B RUN1	
14-Jul-05	9:29:48	11.81	78.63	52.48	7.90	154.86	103.36		SCRUBER B RUN1	
14-Jul-05	9:30:48	11.73	80.34	65.55	8.03	156.79	127.92		SCRUBER B RUN1	
14-Jul-05	9:31:48	12.06	79.64	67.52	7.76	161.19	136.66		SCRUBER B RUN1	
14-Jul-05	9:32:48	12.66	77.52	59.56	7.32	168.42	129.39		SCRUBER B RUN1	
14-Jul-05	9:33:48	12.87	76.66	47.47	7.09	170.98	105.88		SCRUBER B RUN1	
14-Jul-05	9:34:48	12.98	73.54	40.49	7.00	166.22	91.52		SCRUBER B RUN1	
14-Jul-05	9:35:48	13.29	68.80	33.51	6.80	161.77	78.80		SCRUBER B RUN1	
14-Jul-05	9:36:48	13.38	94.59	28.50	6.68	225.04	67.80		SCRUBER B RUN1	
14-Jul-05	9:37:48	13.49	110.00	31.45	6.59	265.60	75.94		SCRUBER B RUN1	**
14-Jul-05	9:38:48	13.72	67.45	27.42	6.40	168.15	68.36		SCRUBER B RUN1	
14-Jul-05	9:39:48	13.82	64.69	23.39	6.34	163.45	59.10		SCRUBER B RUN1	
14-Jul-05	9:40:48	13.61	63.52	23.49	6.49	155.90	57.65		SCRUBER B RUN1	
14-Jul-05	9:41:48	13.42	64.87	26.44	6.65	155.25	63.27		SCRUBER B RUN1	
14-Jul-05	9:42:48	13.47	68.38	27.52	6.64	164.73	66.29		SCRUBER B RUN1	
14-Jul-05	9:43:48	13.36	69.61	23.49	6.75	165.29	55.77		SCRUBER B RUN1	
14-Jul-05	9:44:48	13.20	70.20	26.44	6.81	163.28	61.49		SCRUBER B RUN1	
14-Jul-05	9:45:48	13.34	69.15	24.47	6.77	163.65	57.92		SCRUBER B RUN1	

Source Testing And Consulting Services, Inc. IDLE

7/14/2005 RAYONIER Fuel: Bark & Oil Unit # SCRUBBER B

	Parameter	O2	NOx	CO	CO2	NOx	CO	0	0	Comments	
	Units	%V	ppmV	ppmV	%	@3%O2	@3%O2	0	0		
14-Jul-05	9:46:48	13.21	68.86	25.45	6.81	160.30	59.26			SCRUBER B RUN1	
14-Jul-05	9:47:48	13.19	68.56	27.52	6.80	159.26	63.92			SCRUBER B RUN1	
14-Jul-05	9:48:48	13.18	67.86	24.42	6.83	157.30	56.61			SCRUBER B RUN1	
14-Jul-05	9:49:48	12.98	67.45	30.42	7.05	152.41	68.74			SCRUBER B RUN1	
14-Jul-05	9:50:48	12.81	67.86	35.53	7.14	150.13	78.60			SCRUBER B RUN1	
14-Jul-05	9:51:48	12.90	66.81	37.40	7.16	149.48	83.68			SCRUBER B RUN1	
14-Jul-05	9:52:48	12.72	66.28	37.50	7.29	145.00	82.03			SCRUBER B RUN1	
14-Jul-05	9:53:48	12.82	67.97	40.35	7.16	150.55	89.37			SCRUBER B RUN1	
14-Jul-05	9:54:48	12.82	68.10	39.46	7.14	150.93	87.46			SCRUBER B RUN1	
14-Jul-05	9:55:48	12.61	69.03	43.39	7.36	149.10	93.72			SCRUBER B RUN1	
14-Jul-05	9:56:48	12.72	69.44	42.51	7.28	152.02	93.05			SCRUBER B RUN1	
14-Jul-05	9:57:48	12.89	70.49	38.48	7.05	157.54	85.99			SCRUBER B RUN1	
14-Jul-05	9:58:48	12.83	69.67	36.41	7.22	154.55	80.78			SCRUBER B RUN1	
14-Jul-05	9:59:48	12.77	70.03	38.38	7.19	154.28	84.55			SCRUBER B RUN1	
14-Jul-05	10:00:48	12.57	70.20	41.43	7.33	150.86	89.03			SCRUBER B RUN1	STOP
		12.63	73.88	41.74	7.32	160.31	89.44			AVG	
14-Jul-05	10:04:13	12.55	1.15	0.44	0.87	2.46	0.95			O2=12.53	
14-Jul-05	10:04:18	12.52	1.09	0.44	0.90	2.32	0.95			O2=12.53	
14-Jul-05	10:04:23	12.55	0.97	0.44	0.87	2.08	0.95			O2=12.53	
14-Jul-05	10:04:28	12.52	0.97	0.44	0.87	2.07	0.94			O2=12.53	
14-Jul-05	10:04:33	12.52	0.97	0.44	0.89	2.07	0.94			O2=12.53	
14-Jul-05	10:04:38	12.54	0.97	0.44	0.89	2.07	0.95			O2=12.53	
14-Jul-05	10:04:43	12.49	0.97	0.34	0.86	2.06	0.73			O2=12.53	
14-Jul-05	10:08:54	0.09	93.36	95.98	0.87	80.31	82.56			NOX=92.9 CO=96	
14-Jul-05	10:08:59	0.00	93.36	97.11	0.84	79.96	83.18			NOX=92.9 CO=96	
14-Jul-05	10:09:04	0.09	93.35	97.01	0.88	80.31	83.45			NOX=92.9 CO=96	
14-Jul-05	10:09:09	0.09	93.35	96.08	0.87	80.30	82.64			NOX=92.9 CO=96	
14-Jul-05	10:09:14	0.11	93.41	96.08	0.86	80.42	82.72			NOX=92.9 CO=96	
14-Jul-05	10:09:19	0.05	93.41	95.98	0.84	80.19	82.39			NOX=92.9 CO=96	
14-Jul-05	10:10:20	12.18	93.23	89.68	9.01	191.36	184.06			CO2=9	
14-Jul-05	10:10:25	12.28	93.23	67.60	9.00	193.65	140.40			CO2=9	
14-Jul-05	10:10:30	12.33	93.24	38.29	8.99	194.83	80.00			CO2=9	
14-Jul-05	10:10:35	12.45	53.19	38.18	9.02	112.73	80.92			CO2=9	
14-Jul-05	10:10:40	12.40	53.19	16.20	9.00	112.01	34.12			CO2=9	
14-Jul-05	10:14:53	0.07	48.62	47.68	0.85	41.79	40.98			NOX=48.2 CO=47.9	
14-Jul-05	10:14:59	0.09	48.62	48.71	0.85	41.82	41.90			NOX=48.2 CO=47.9	
14-Jul-05	10:15:04	0.00	48.62	48.71	0.81	41.64	41.72			NOX=48.2 CO=47.9	
14-Jul-05	10:15:09	0.03	48.62	47.78	0.82	41.69	40.97			NOX=48.2 CO=47.9	
14-Jul-05	10:15:14	0.06	48.68	47.78	0.85	41.82	41.05			NOX=48.2 CO=47.9	
14-Jul-05	10:15:19	0.04	48.68	47.68	0.81	41.77	40.91			NOX=48.2 CO=47.9	
14-Jul-05	10:18:11	12.05	76.00	57.40	7.85	153.78	116.14			SCRUBBER B RUN 2	START
14-Jul-05	10:19:11	12.98	75.53	44.42	7.18	170.65	100.37			SCRUBBER B RUN 2	
14-Jul-05	10:20:12	12.89	76.70	38.43	7.24	171.38	85.87			SCRUBBER B RUN 2	
14-Jul-05	10:21:12	12.61	76.88	37.35	7.41	166.02	80.66			SCRUBBER B RUN 2	
14-Jul-05	10:22:12	12.77	77.35	46.49	7.34	170.22	102.31			SCRUBBER B RUN 2	
14-Jul-05	10:23:12	12.92	77.81	49.44	7.19	174.61	110.94			SCRUBBER B RUN 2	
14-Jul-05	10:24:12	13.23	78.06	39.41	6.95	182.24	92.01			SCRUBBER B RUN 2	
14-Jul-05	10:25:12	13.50	75.47	30.37	6.79	182.58	73.47			SCRUBBER B RUN 2	
14-Jul-05	10:26:12	13.32	74.12	30.47	6.87	175.11	71.99			SCRUBBER B RUN 2	
14-Jul-05	10:27:12	13.35	74.35	28.40	6.85	176.18	67.31			SCRUBBER B RUN 2	
14-Jul-05	10:28:12	13.41	75.71	32.38	6.89	180.94	77.39			SCRUBBER B RUN 2	
14-Jul-05	10:29:12	13.26	75.48	28.45	7.00	176.89	66.68			SCRUBBER B RUN 2	
14-Jul-05	10:30:12	12.90	76.78	38.48	7.29	171.86	86.13			SCRUBBER B RUN 2	
14-Jul-05	10:31:12	13.07	80.05	39.46	7.12	182.90	90.16			SCRUBBER B RUN 2	
14-Jul-05	10:32:12	13.01	78.93	38.48	7.22	178.99	87.26			SCRUBBER B RUN 2	
14-Jul-05	10:33:12	12.87	78.35	35.43	7.32	174.68	79.00			SCRUBBER B RUN 2	
14-Jul-05	10:34:12	12.83	77.11	34.45	7.38	170.93	76.36			SCRUBBER B RUN 2	
14-Jul-05	10:35:12	12.95	77.52	33.47	7.27	174.55	75.35			SCRUBBER B RUN 2	
14-Jul-05	10:36:12	12.41	77.41	44.47	7.59	163.16	93.74			SCRUBBER B RUN 2	
14-Jul-05	10:37:12	12.61	79.41	44.47	7.52	171.49	96.04			SCRUBBER B RUN 2	

Source Testing And Consulting Services, Inc. IDLE

7/14/2005		RAYONIER		Fuel:	Bark & Oil			Unit #	SCRUBBER B
	Parameter	O2	NOx	CO	CO2	NOx	CO	0	0 Comments
	Units	%V	ppmV	ppmV	%	@3%O2	@3%O2	0	0
14-Jul-05	10:38:12	12.70	78.88	36.51	7.44	172.28	79.75		SCRUBBER B RUN 2
14-Jul-05	10:39:12	12.74	76.36	33.47	7.37	167.49	73.40		SCRUBBER B RUN 2
14-Jul-05	10:40:12	12.85	76.82	35.43	7.33	170.92	78.83		SCRUBBER B RUN 2
14-Jul-05	10:41:12	12.67	76.88	38.48	7.48	167.12	83.64		SCRUBBER B RUN 2
14-Jul-05	10:42:12	12.59	77.71	37.40	7.45	167.47	80.59		SCRUBBER B RUN 2
14-Jul-05	10:43:12	12.43	77.30	43.49	7.63	163.39	91.93		SCRUBBER B RUN 2
14-Jul-05	10:44:12	12.55	78.47	48.50	7.58	168.20	103.98		SCRUBBER B RUN 2
14-Jul-05	10:45:12	12.45	78.35	41.53	7.60	165.95	87.95		SCRUBBER B RUN 2
14-Jul-05	10:46:12	12.65	78.23	41.53	7.44	169.75	90.10		SCRUBBER B RUN 2
14-Jul-05	10:47:12	12.81	77.88	34.45	7.38	172.21	76.18		SCRUBBER B RUN 2
14-Jul-05	10:48:12	12.56	77.52	41.48	7.58	166.46	89.07		SCRUBBER B RUN 2
14-Jul-05	10:49:12	12.64	78.11	42.46	7.50	169.28	92.02		SCRUBBER B RUN 2
14-Jul-05	10:50:12	12.68	76.76	41.48	7.44	167.10	90.29		SCRUBBER B RUN 2
14-Jul-05	10:51:12	13.24	75.59	33.42	7.03	176.70	78.12		SCRUBBER B RUN 2
14-Jul-05	10:52:12	13.50	74.00	26.34	6.78	179.01	63.72		SCRUBBER B RUN 2
14-Jul-05	10:53:12	13.85	70.55	24.47	6.50	179.11	62.13		SCRUBBER B RUN 2
14-Jul-05	10:54:12	14.17	66.56	22.41	6.17	176.94	59.57		SCRUBBER B RUN 2
14-Jul-05	10:55:12	14.29	61.93	21.33	6.16	167.81	57.79		SCRUBBER B RUN 2
14-Jul-05	10:56:12	14.28	60.65	24.47	6.16	164.05	66.19		SCRUBBER B RUN 2
14-Jul-05	10:57:12	14.39	60.46	26.44	6.02	166.13	72.64		SCRUBBER B RUN 2
14-Jul-05	10:58:12	14.31	59.76	26.44	6.15	162.41	71.86		SCRUBBER B RUN 2
14-Jul-05	10:59:12	14.22	59.76	26.44	6.13	160.08	70.83		SCRUBBER B RUN 2
14-Jul-05	11:00:12	14.36	59.18	30.37	6.08	161.92	83.10		SCRUBBER B RUN 2
14-Jul-05	11:01:12	14.19	59.30	39.41	6.24	158.21	105.16		SCRUBBER B RUN 2
14-Jul-05	11:02:12	14.05	60.05	40.40	6.29	156.89	105.54		SCRUBBER B RUN 2
14-Jul-05	11:03:12	13.98	60.52	35.38	6.42	156.66	91.59		SCRUBBER B RUN 2
14-Jul-05	11:04:12	13.96	61.70	40.40	6.37	159.10	104.15		SCRUBBER B RUN 2
14-Jul-05	11:05:12	13.92	59.70	39.31	6.37	153.11	100.83		SCRUBBER B RUN 2
14-Jul-05	11:06:12	13.80	60.36	43.44	6.50	152.07	109.45		SCRUBBER B RUN 2
14-Jul-05	11:07:12	13.82	60.86	38.43	6.45	153.92	97.16		SCRUBBER B RUN 2
14-Jul-05	11:08:12	13.87	60.35	46.58	6.54	153.70	118.63		SCRUBBER B RUN 2
14-Jul-05	11:09:12	13.62	60.13	43.54	6.63	147.80	107.02		SCRUBBER B RUN 2
14-Jul-05	11:10:12	13.31	61.00	54.55	6.93	143.93	128.69		SCRUBBER B RUN 2
14-Jul-05	11:11:12	13.12	60.53	52.58	7.09	139.25	120.96		SCRUBBER B RUN 2
14-Jul-05	11:12:12	12.97	61.70	54.55	7.19	139.35	123.19		SCRUBBER B RUN 2
14-Jul-05	11:13:12	12.92	62.88	57.59	7.24	140.96	129.11		SCRUBBER B RUN 2
14-Jul-05	11:14:12	13.06	63.52	57.49	7.08	144.98	131.23		SCRUBBER B RUN 2
14-Jul-05	11:15:12	12.93	62.82	57.59	7.18	141.05	129.31		SCRUBBER B RUN 2
14-Jul-05	11:16:12	12.96	62.30	55.53	7.21	140.40	125.14		SCRUBBER B RUN 2
14-Jul-05	11:17:12	12.68	62.05	68.50	7.42	135.12	149.16		SCRUBBER B RUN 2
14-Jul-05	11:18:12	12.59	63.16	72.53	7.42	135.99	156.16		SCRUBBER B RUN 2 STOP
		13.21	70.49	40.13	7.00	163.99	92.87		AVG
14-Jul-05	11:22:04	0.04	93.11	96.44	0.84	79.91	82.76		NOX=92.9 CO=96.0
14-Jul-05	11:22:09	0.04	93.24	95.43	0.84	80.00	81.88		NOX=92.9 CO=96.0
14-Jul-05	11:22:14	0.09	93.23	95.43	0.87	80.20	82.10		NOX=92.9 CO=96.0
14-Jul-05	11:22:19	0.13	93.28	93.33	0.85	80.38	80.42		NOX=92.9 CO=96.0
14-Jul-05	11:22:24	0.07	93.28	93.43	0.88	80.18	80.31		NOX=92.9 CO=96.0
14-Jul-05	11:25:08	12.61	0.48	0.50	0.83	1.04	1.08		O2=12.53
14-Jul-05	11:25:13	12.60	0.48	0.40	0.85	1.04	0.86		O2=12.53
14-Jul-05	11:25:18	12.51	0.48	0.40	0.83	1.03	0.86		O2=12.53
14-Jul-05	11:25:23	12.56	0.48	0.40	0.83	1.03	0.86		O2=12.53
14-Jul-05	11:25:28	12.54	0.42	0.50	0.83	0.91	1.07		O2=12.53
14-Jul-05	11:25:33	12.65	0.42	0.50	0.86	0.92	1.09		O2=12.53
14-Jul-05	11:26:17	12.46	0.48	0.40	8.98	1.02	0.85		CO2=9
14-Jul-05	11:26:22	12.50	0.49	0.40	9.03	1.04	0.85		CO2=9
14-Jul-05	11:26:27	12.48	0.48	0.50	9.00	1.02	1.06		CO2=9
14-Jul-05	11:26:32	12.56	0.48	0.60	9.02	1.03	1.29		CO2=9
14-Jul-05	11:26:37	12.45	0.48	0.40	9.00	1.02	0.85		CO2=9
14-Jul-05	11:26:42	12.52	0.48	0.40	9.03	1.03	0.86		CO2=9
14-Jul-05	11:26:47	12.46	0.47	0.50	9.03	1.00	1.06		CO2=9

Source Testing And Consulting Services, Inc. IDLE

7/14/2005		RAYONIER		Fuel:	Bark & Oil			Unit #	SCRUBBER B	
	Parameter	O2	NOx	CO	CO2	NOx	CO	0	0	Comments
	Units	%V	ppmV	ppmV	%	@3%O2	@3%O2	0	0	
14-Jul-05	11:31:28	0.06	48.51	47.78	0.87	41.66	41.03			NOX=48.2 CO=47.9
14-Jul-05	11:31:32	0.07	48.52	47.78	0.89	41.70	41.07			NOX=48.2 CO=47.9
14-Jul-05	11:31:37	0.01	48.51	47.78	0.87	41.57	40.94			NOX=48.2 CO=47.9
14-Jul-05	11:31:42	0.03	48.52	47.88	0.88	41.62	41.07			NOX=48.2 CO=47.9
14-Jul-05	11:31:47	0.07	48.51	47.78	0.89	41.70	41.07			NOX=48.2 CO=47.9
14-Jul-05	11:31:52	0.03	48.52	47.88	0.85	41.61	41.06			NOX=48.2 CO=47.9
14-Jul-05	11:31:57	0.09	48.58	47.78	0.88	41.79	41.10			NOX=48.2 CO=47.9
14-Jul-05	11:32:02	0.06	48.58	47.78	0.85	41.71	41.03			NOX=48.2 CO=47.9
14-Jul-05	11:36:59	11.86	69.03	54.07	7.71	136.73	107.10			SCRUBBER B RUN 3 START
14-Jul-05	11:40:00	11.37	68.39	75.12	8.29	128.51	141.16			SCRUBBER B RUN 3
14-Jul-05	11:41:00	12.10	70.79	60.47	7.82	144.01	123.02			SCRUBBER B RUN 3
14-Jul-05	11:42:00	11.60	72.83	66.66	8.02	140.15	128.27			SCRUBBER B RUN 3
14-Jul-05	11:43:00	11.88	71.49	70.89	8.00	141.79	140.61			SCRUBBER B RUN 3
14-Jul-05	11:44:00	12.04	70.14	56.24	7.88	141.62	113.55			SCRUBBER B RUN 3
14-Jul-05	11:45:00	11.85	69.80	56.51	8.04	138.10	111.81			SCRUBBER B RUN 3
14-Jul-05	11:46:00	12.08	69.84	47.57	7.90	141.77	96.55			SCRUBBER B RUN 3
14-Jul-05	11:47:00	11.83	69.26	75.57	8.01	136.64	149.09			SCRUBBER B RUN 3
14-Jul-05	11:48:00	11.61	70.49	56.61	8.11	135.81	109.06			SCRUBBER B RUN 3
14-Jul-05	11:49:00	11.77	69.56	71.54	8.10	136.43	140.32			SCRUBBER B RUN 3
14-Jul-05	11:50:00	11.58	69.44	56.51	8.23	133.36	108.52			SCRUBBER B RUN 3
14-Jul-05	11:51:00	11.11	68.85	99.55	8.57	125.86	181.98			SCRUBBER B RUN 3
14-Jul-05	11:52:00	11.14	68.20	112.53	8.54	125.11	206.41			SCRUBBER B RUN 3
14-Jul-05	11:53:00	11.15	69.03	102.60	8.51	126.75	188.40			SCRUBBER B RUN 3
14-Jul-05	11:54:00	11.10	69.03	117.54	8.57	126.02	214.58			SCRUBBER B RUN 3
14-Jul-05	11:55:02	11.05	69.62	89.53	8.66	126.50	162.67			SCRUBBER B RUN 3
14-Jul-05	11:56:02	11.46	68.97	114.59	8.28	130.73	217.20			SCRUBBER B RUN 3
14-Jul-05	11:57:02	11.83	69.80	91.49	8.13	137.82	180.66			SCRUBBER B RUN 3
14-Jul-05	11:58:02	12.81	70.67	76.56	7.39	156.37	169.39			SCRUBBER B RUN 3
14-Jul-05	11:59:02	12.70	68.20	53.56	7.42	148.87	116.91			SCRUBBER B RUN 3
14-Jul-05	12:00:02	12.70	66.62	48.55	7.43	145.47	106.00			SCRUBBER B RUN 3
14-Jul-05	12:01:02	12.58	64.64	42.55	7.44	139.09	91.57			SCRUBBER B RUN 3
14-Jul-05	12:02:02	12.46	64.46	53.56	7.55	136.69	113.58			SCRUBBER B RUN 3
14-Jul-05	12:03:02	12.27	64.69	66.53	7.69	134.14	137.95			SCRUBBER B RUN 3
14-Jul-05	12:04:02	12.00	64.64	69.58	7.96	129.99	139.93			SCRUBBER B RUN 3
14-Jul-05	12:05:02	12.42	65.57	64.57	7.62	138.40	136.28			SCRUBBER B RUN 3
14-Jul-05	12:06:02	12.26	64.75	66.53	7.70	134.23	137.92			SCRUBBER B RUN 3
14-Jul-05	12:07:02	11.89	64.40	73.51	7.96	128.00	146.10			SCRUBBER B RUN 3
14-Jul-05	12:08:02	12.13	66.34	86.58	7.86	135.41	176.73			SCRUBBER B RUN 3
14-Jul-05	12:09:02	11.81	66.38	80.59	8.07	130.75	158.72			SCRUBBER B RUN 3
14-Jul-05	12:10:02	11.82	66.92	104.57	8.06	131.90	206.11			SCRUBBER B RUN 3
14-Jul-05	12:11:02	11.75	68.56	99.55	8.08	134.04	194.65			SCRUBBER B RUN 3
14-Jul-05	12:12:02	11.73	68.15	139.55	8.08	133.08	272.49			SCRUBBER B RUN 3
14-Jul-05	12:13:02	11.88	68.14	86.58	8.03	135.16	171.73			SCRUBBER B RUN 3
14-Jul-05	12:14:02	11.95	68.57	92.58	7.93	137.19	185.23			SCRUBBER B RUN 3
14-Jul-05	12:15:02	11.95	69.21	96.60	7.95	138.40	193.19			SCRUBBER B RUN 3
14-Jul-05	12:16:02	11.71	68.51	84.52	8.09	133.48	164.68			SCRUBBER B RUN 3
14-Jul-05	12:17:02	11.87	68.04	96.51	8.05	134.80	191.21			SCRUBBER B RUN 3
14-Jul-05	12:18:02	11.90	66.87	81.47	7.96	133.03	162.08			SCRUBBER B RUN 3
14-Jul-05	12:19:02	11.79	67.92	96.51	8.03	133.44	189.61			SCRUBBER B RUN 3
14-Jul-05	12:20:02	11.52	68.20	95.62	8.27	130.11	182.41			SCRUBBER B RUN 3
14-Jul-05	12:21:02	11.80	69.21	101.62	8.11	136.08	199.81			SCRUBBER B RUN 3
14-Jul-05	12:22:02	12.05	70.26	91.59	7.85	142.10	185.25			SCRUBBER B RUN 3
14-Jul-05	12:23:02	12.28	69.38	61.52	7.75	144.01	127.69			SCRUBBER B RUN 3
14-Jul-05	12:24:02	12.14	67.92	57.59	7.85	138.83	117.72			SCRUBBER B RUN 3
14-Jul-05	12:25:02	12.48	66.93	58.47	7.59	142.23	124.27			SCRUBBER B RUN 3
14-Jul-05	12:26:02	12.55	66.44	44.52	7.51	142.37	95.39			SCRUBBER B RUN 3
14-Jul-05	12:27:02	12.44	68.15	44.52	7.57	144.13	94.14			SCRUBBER B RUN 3
14-Jul-05	12:28:02	12.53	68.27	49.53	7.52	146.07	105.97			SCRUBBER B RUN 3
14-Jul-05	12:29:02	12.81	68.09	35.48	7.29	150.72	78.54			SCRUBBER B RUN 3
14-Jul-05	12:30:02	12.97	67.92	33.51	7.21	153.38	75.68			SCRUBBER B RUN 3

Source Testing And Consulting Services, Inc.

IDLE

7/14/2005		RAYONIER		Fuel:	Bark & Oil			Unit #	SCRUBBER B
	Parameter	O2	NOx	CO	CO2	NOx	CO	0	0 Comments
	Units	%V	ppmV	ppmV	%	@3%O2	@3%O2	0	0
14-Jul-05	12:31:02	12.44	67.68	47.57	7.59	143.25	100.67		SCRUBBER B RUN 3
14-Jul-05	12:32:02	12.11	69.44	65.35	7.88	141.35	133.03		SCRUBBER B RUN 3
14-Jul-05	12:33:02	12.37	71.66	53.46	7.69	150.37	112.18		SCRUBBER B RUN 3
14-Jul-05	12:34:02	12.31	73.24	45.60	7.67	152.68	95.05		SCRUBBER B RUN 3
14-Jul-05	12:35:02	12.42	73.13	59.65	7.67	154.28	125.86		SCRUBBER B RUN 3
14-Jul-05	12:36:02	12.48	71.91	60.54	7.59	152.86	128.69		SCRUBBER B RUN 3
14-Jul-05	12:37:02	12.38	72.43	51.50	7.67	152.15	108.18		SCRUBBER B RUN 3
14-Jul-05	12:41:14	12.56	3.43	1.38	0.93	7.36	2.95		o2=12.53
14-Jul-05	12:41:19	12.48	3.44	1.38	0.90	7.32	2.93		o2=12.53
14-Jul-05	12:41:24	12.52	2.26	1.38	0.89	4.83	2.94		o2=12.53
14-Jul-05	12:41:29	12.61	2.26	1.38	0.92	4.88	2.97		o2=12.53
14-Jul-05	12:41:34	12.49	2.26	0.49	0.89	4.81	1.05		o2=12.53
14-Jul-05	12:41:39	12.50	2.02	0.49	0.92	4.31	1.05		o2=12.53
14-Jul-05	12:41:44	12.51	2.02	0.49	0.89	4.32	1.05		o2=12.53
14-Jul-05	12:41:49	12.60	2.02	0.49	0.91	4.37	1.06		o2=12.53
14-Jul-05	12:41:54	12.55	1.80	0.49	0.93	3.86	1.05		o2=12.53
14-Jul-05	12:41:59	12.49	1.80	0.49	0.91	3.83	1.05		o2=12.53
14-Jul-05	12:42:04	12.55	1.62	0.49	0.93	3.48	1.05		o2=12.53
14-Jul-05	12:44:41	0.10	93.00	97.20	0.84	80.03	83.65		NOX=92.9 CO=96
14-Jul-05	12:44:47	0.07	93.12	96.07	0.86	80.04	82.58		NOX=92.9 CO=96
14-Jul-05	12:44:52	0.04	93.11	96.17	0.84	79.91	82.54		NOX=92.9 CO=96
14-Jul-05	12:44:57	0.02	93.11	96.07	0.84	79.83	82.37		NOX=92.9 CO=96
14-Jul-05	12:45:02	0.07	93.11	97.20	0.87	80.03	83.55		NOX=92.9 CO=96
14-Jul-05	12:45:07	0.07	93.11	97.20	0.87	80.03	83.55		NOX=92.9 CO=96
14-Jul-05	12:45:12	0.00	93.11	97.20	0.83	79.74	83.25		NOX=92.9 CO=96
14-Jul-05	12:47:10	0.00	48.51	47.78	0.83	41.55	40.92		NOX=48.2 CO=47.9
14-Jul-05	12:47:16	0.04	48.58	46.74	0.87	41.68	40.11		NOX=48.2 CO=47.9
14-Jul-05	12:47:21	0.03	48.58	46.74	0.86	41.66	40.09		NOX=48.2 CO=47.9
14-Jul-05	12:47:26	0.03	48.57	46.74	0.83	41.65	40.09		NOX=48.2 CO=47.9
14-Jul-05	12:47:31	0.04	48.57	46.74	0.83	41.68	40.12		NOX=48.2 CO=47.9
14-Jul-05	12:47:36	0.05	48.58	47.88	0.83	41.71	41.11		NOX=48.2 CO=47.9
14-Jul-05	12:47:41	0.04	48.58	47.78	0.83	41.68	40.99		NOX=48.2 CO=47.9
14-Jul-05	12:47:46	0.02	48.57	47.78	0.85	41.64	40.96		NOX=48.2 CO=47.9
14-Jul-05	12:48:39	12.44	0.68	15.22	9.01	102.97	32.19		CO2=9
14-Jul-05	12:48:44	12.41	0.06	5.62	8.98	54.97	11.86		CO2=9
14-Jul-05	12:48:49	12.41	0.06	5.73	8.98	54.96	12.08		CO2=9
14-Jul-05	12:48:54	12.44	0.02	1.39	8.99	4.27	2.95		CO2=9
14-Jul-05	12:48:59	12.53	0.02	1.19	9.02	4.32	2.54		CO2=9
14-Jul-05	12:49:04	12.50	0.02	0.46	9.02	4.30	0.99		CO2=9
14-Jul-05	12:49:09	12.50	0.73	0.57	9.01	1.56	1.21		CO2=9
14-Jul-05	12:49:14	12.43	0.73	0.36	9.00	1.55	0.76		CO2=9
14-Jul-05	12:49:19	12.49	0.73	0.36	8.99	1.56	0.77		CO2=9

Source Testing And Consulting Services, Inc.
SRB

6/8/2005		RAYONIER						Unit #	SRB			
	Parameter	O2	NOx	SO2	CO	CO2	NOX	SO2	0	Comments		
	Units	%V	ppmV	ppmV	ppmV	%	@7%O2	@7%O2	0			
6/8/05	8:59:24	5.06	596.17	134.67	2.06	15.10	523.04	118.15		SRB RA 1 PM R1		START PM RUN 1
6/8/05	9:00:24	4.96	607.17	140.07	2.06	15.16	529.57	122.17		SRB RA 1 PM R1		
6/8/05	9:01:24	5.11	613.17	141.84	1.97	15.07	539.88	124.89		SRB RA 1 PM R1		
6/8/05	9:02:24	5.14	613.17	144.79	2.06	15.07	540.64	127.66		SRB RA 1 PM R1		
6/8/05	9:03:24	5.13	624.18	147.05	2.06	15.08	550.00	129.58		SRB RA 1 PM R1		
6/8/05	9:04:24	5.09	599.21	149.51	2.06	15.12	526.94	131.47		SRB RA 1 PM R1		
6/8/05	9:05:24	5.05	592.24	154.32	2.16	15.15	519.43	135.35		SRB RA 1 PM R1		
6/8/05	9:06:24	5.01	591.16	154.91	2.16	15.17	517.04	135.49		SRB RA 1 PM R1		
6/8/05	9:07:24	5.11	595.28	157.76	2.06	15.14	524.05	138.89		SRB RA 1 PM R1		
6/8/05	9:08:24	5.08	597.25	162.19	2.06	15.12	524.72	142.49		SRB RA 1 PM R1		
6/8/05	9:09:24	5.07	603.24	170.74	2.06	15.16	529.74	149.93		SRB RA 1 PM R1		
6/8/05	9:10:24	5.10	604.32	171.33	2.06	15.18	531.51	150.68		SRB RA 1 PM R1		
6/8/05	9:11:24	5.00	595.18	173.88	2.06	15.24	520.48	152.06		SRB RA 1 PM R1		
6/8/05	9:12:24	5.01	612.29	179.39	2.06	15.23	535.52	156.89		SRB RA 1 PM R1		
6/8/05	9:13:24	4.97	605.21	186.66	2.06	15.26	528.18	162.90		SRB RA 1 PM R1		
6/8/05	9:14:24	5.01	611.20	203.44	3.05	15.27	534.65	177.96		SRB RA 1 PM R1		
6/8/05	9:15:24	5.00	596.17	201.12	2.06	15.27	521.18	175.82		SRB RA 1 PM R1		
6/8/05	9:16:24	4.99	601.28	206.71	3.05	15.30	525.32	180.60		SRB RA 1 PM R1		
6/8/05	9:17:24	5.04	603.24	210.93	1.97	15.26	528.59	184.83		SRB RA 1 PM R1		
6/8/05	9:18:24	4.74	595.07	211.98	1.92	15.02	511.96	182.37		SRB RA 1 PM R1		
6/8/05	9:19:24	4.74	606.07	215.12	1.92	15.05	521.35	185.05		SRB RA 1 PM R1		
6/8/05	9:20:24	4.69	601.06	214.93	1.82	15.05	515.31	184.26		SRB RA 1 PM R1		
6/8/05	9:21:24	4.73	605.09	217.68	3.88	15.00	520.26	187.16		SRB RA 1 PM R1		
6/8/05	9:38:38	4.81	604.11	244.98	1.82	14.92	522.04	211.69		RA R2 PM R1	START	CEM CAL
6/8/05	9:39:38	4.72	611.09	253.33	1.92	15.03	524.86	217.58		RA R2 PM R1		
6/8/05	9:40:38	5.11	584.06	259.52	2.80	14.74	514.06	228.42		RA R2 PM R1		
6/8/05	9:41:38	4.73	586.12	270.33	1.82	15.03	503.99	232.45		RA R2 PM R1		
6/8/05	9:42:38	4.86	596.05	279.87	1.82	14.94	516.37	242.46		RA R2 PM R1		
6/8/05	9:43:38	4.67	586.12	284.78	1.92	15.07	501.93	243.88		RA R2 PM R1		
6/8/05	9:44:38	4.64	589.07	286.94	1.82	15.12	503.62	245.32		RA R2 PM R1		
6/8/05	9:45:38	4.57	568.14	288.22	25.01	15.17	483.46	245.26		RA R2 PM R1		
6/8/05	9:46:38	4.66	579.14	293.33	5.95	15.08	495.73	251.08		RA R2 PM R1		
6/8/05	9:47:38	4.62	582.09	294.51	1.92	15.10	497.13	251.52		RA R2 PM R1		
6/8/05	9:48:38	4.87	578.06	296.48	1.82	14.96	501.18	257.04		RA R2 PM R1		
6/8/05	9:49:38	4.71	597.03	287.73	1.82	14.99	512.59	247.04		RA R2 PM R1		
6/8/05	9:50:38	4.65	582.09	279.38	6.83	15.12	497.80	238.92		RA R2 PM R1		
6/8/05	9:51:38	4.58	573.15	284.58	2.90	15.15	488.16	242.39		RA R2 PM R1		
6/8/05	9:52:38	4.55	570.10	280.26	1.82	15.14	484.76	238.31		RA R2 PM R1		
6/8/05	9:53:38	4.58	574.13	283.31	1.92	15.14	489.00	241.30		RA R2 PM R1		
6/8/05	9:54:38	4.65	573.15	286.94	1.82	15.07	490.38	245.50		RA R2 PM R1		
6/8/05	9:55:38	4.56	573.15	291.37	2.90	15.14	487.43	247.79		RA R2 PM R1		

Row #

ATTACHMENT 1

2 **Annual Production Change to the Proposed New Maximum Production**

Row #	Year	Net ADMT/yr	Change	% Change	Change Ratio
5	1996	149,957	25,043	14.31%	1.167
6	1997	149,426	25,574	14.61%	1.171
7	1998	132,016	42,984	24.56%	1.326
8	1999	119,689	55,311	31.61%	1.462
9	2000	151,515	23,485	13.42%	1.155
10	2001	146,247	28,753	16.43%	1.197
11	2002	145,895	29,105	16.63%	1.199
12	2003	144,976	30,024	17.16%	1.207
13	2004	145,883	29,117	16.64%	1.200

15 New Production: **175,000**

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

Row #	Year	VOC		SO_2		CO	
20	Pulping Systems (VGS)						
21	2000			79		0	
22	2001			51.84		0	
23	2002			21.36		0	
24	2003	26.72		13.34		0	
25	2004	46.52		11.25		0	
26	Baseline	36.62		65.42		NA	
27	Increase 8%		2.93				0
28	Increase 16.70%		6.116		10.925		
29	Bleaching Systems						
30	2003	178.17		0			
31	2004	177.84		0			
32	Baseline	178		NA			
33	HCE blow heat recovey	-71.2					
34	Increase 8% no heat recovery project		14.24				
35	Increase 16.70% and recovery project		-41.47				25.12
36	Evaporators						
37	2003	50.72		0		0	
38	2004	56.72		0		0	
39	Baseline	53.72		NA		NA	
40	Increase 8%		4.297		0		0
41	Increase 16.70%		8.971				
42	Wastewater Treatment System						
43	2003	76.89		0		0	
44	2004	55.64		0		0	
45	Baseline	66.26		NA		NA	
46	Increase 8%		5.301		0		0
47	Increase 16.70%		11.065				
48	Grand Total at 8% increase and no heat recovery project		26.77				
49	Grand Total at 16.70% increase and heat recovery project		-15.318		10.925		25.12
50–51	Significance Level		40		40		100

Row #

ATTACHMENT 1

Pulping Systems (VGS)

Table 13	Pulping Systems		
Year	Production ADMT/yr	VOC Ton/yr	SO2 Ton/yr
2000	151,515		79.00
2001	146,247		51.84
2002	145,895		21.36
2003	144,976	26.72	13.34
2004	145,883	46.52	11.25
Baseline		36.62	65.42
Increase 8%		2.93	
Increase 16.70%		6.12	10.93

2004 Pulping System [VGS]	Uncontrolled MeOH:	1.52	lb MeOH/ADMT	Pulping MeOH/VOC ratio: 0.975
	Production	Ton MeOH/yr	Ton VOC/yr	% Change from 1996
1996	149,957	114	117	0.0%
2003	144,976	110	113	-3.3%
2004	145,883	111	114	-2.7%
Present PSD Limit	153,205	116	119	2.2%
Proposed PSD Limit	175,000	133	136	16.7%

Copy of AOR Calculations for Pulping System VOC

Methanol & VOC 2004				Before Control							
	VGS Stack Tests 1991 - 2001:			25.39	lb MeOH/hr	26	tests	G:RWH/MACT Methanol/Methanol Data Review SortII 9904.xls.			
				1.10	lb MeOH/ODUBT	26	tests	24	ODUBT/hr		
	VGS Stack Tests 10/2003 Worst Case Scenario			21.80	lb MeOH/hr	3	tests	568	ODUBT/day		
				0.92	lb MeOH/ODUBT	3	tests	572	ADUBMT/day		
			Weighted Average	25.01	lb MeOH/hr	29	tests				
				1.08	lb MeOH/ODUBT	29	tests	567	ODUBT/day		
			ODUBT/yr:	200,948				VGS Stack Tests 10/2003			
			ADMT/yr:	145,883							
Ton MeOH/yr	45.4		Method	1							
lb/MeOH/day	256.4				VOC per	After Control:	0.46	lb/ODUBT	VGS Stack Tests 2004		11.6
					FDEP	After Control:	45.37	T MeOH/yr			lb/hr
Total HAPS				VOC [EPA 500 Series]	62-204.200	Total Year	45.37	T MeOH/yr			278.4
	Methanol			No	Yes			MeOH removal eff.	58%		
	45.37	T MeOH/yr									
					Yes						
	Acetaldehyde			No							
	0.0048	lb/ADUBT Pulp									
	223275.8763	ADUBT/yr Pulp									
	0.535862103	Ton /yr									
	Benzene			Yes	Yes						
	0.000015	lb/ADUBT Pulp									
	223275.8763	ADUBT/yr Pulp									
	0.001674569	Ton /yr									
	Acrolein			No	Yes						
	0.000105	lb/ADUBT Pulp									
	223275.8763	ADUBT/yr Pulp									
	0.011721984	Ton /yr									
	Arsenic			No	No						
	0	lb/ton RLS									
	241500	RLS/yr									
	0	Ton /yr									
	Chloromethane			Yes	Yes						
	0	lb/ton RLS									
	241500	RLS/yr									
	0	Ton /yr									
	Barium Compounds			No	No						
	0	lb/ton RLS									
	241500	RLS/yr									
	0	Ton /yr									
	Carbon Tetrachloride			Yes	Yes						
	0.00115	lb/ADUBT Pulp									

Row #

ATTACHMENT 1

117		223275.8763	ADUBT/yr Pulp									
118		0.128383629	Ton /yr									
119		Carbon Disulfide			Yes	Yes						
120		0	lb/ton RLS									
121		241500	RLS/yr									
122		0	Ton /yr									
123		Chromium Comp.			No	No						
124		0	lb/ton RLS									
125		241500	RLS/yr									
126		0	Ton /yr									
127		Cobalt Comp.			No	No						
128		0	lb/ton RLS									
129		241500	RLS/yr									
130		0	Ton /yr									
131		Copper Comp.			No	No						
132		0	lb/ton RLS									
133		241500	RLS/yr									
134		0	Ton /yr									
135		Dichloromethane			No	Yes						
136		0.00045	lb/ADUBT Pulp									
137		223275.8763	ADUBT/yr Pulp									
138		0.050237072	Ton /yr									
139		n-Hexane			No	Yes						
140		0.0001	lb/ADUBT Pulp									
141		223275.8763	ADUBT/yr Pulp									
142		0.011163794	Ton /yr									
143		Methyl Isobutyl Ketone			No	Yes						
144		0.000105	lb/ADUBT Pulp									
145		223275.8763	ADUBT/yr Pulp									
146		0.011721984	Ton /yr									
147		Lead Compounds			No	No						
148		0	lb/ton RLS									
149		241500	RLS/yr									
150		0	Ton /yr									
151		Manganese Comp.			No	No						
152		0	lb/ton RLS									
153		241500	RLS/yr									
154		0	Ton /yr									
155		Mercury Comp.			No	No						
156		0	lb/ton RLS									
157		241500	RLS/yr									
158		0	Ton /yr									
159		Napthalene			Yes	Yes						
160		0	lb/ton RLS									
161		241500	RLS/yr									
162		0	Ton /yr									
163		Nickel Comp.			No	No						
164		0	lb/ton RLS									
165		241500	RLS/yr									
166		0.067	Ton /yr									
167		Tetrachloroethylene			No	Yes						
168		0.000315	lb/ADUBT Pulp									
169		223275.8763	ADUBT/yr Pulp									
170		0.035165951	Ton /yr									
171		Styrene			Yes	Yes						
172		0.0000235	lb/ADUBT Pulp									
173		223275.8763	ADUBT/yr Pulp									
174		0.002623492	Ton /yr									
175		1,2,4 Trichlorobenzene			No	Yes						
176		0.00011	lb/ADUBT Pulp									
177		223275.8763	ADUBT/yr Pulp									
178		0.012280173	Ton /yr									
179		Toluene			Yes	Yes						
180		0.00066	lb/ADUBT Pulp									
181		223275.8763	ADUBT/yr Pulp									
182		0.073681039	Ton /yr									

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Row #												
183		1,1,1-Trichloroethane			Yes	No						
184		0.0016	lb/ADUBT Pulp									
185		223275.8763	ADUBT/yr Pulp									
186		0.178620701	Ton /yr									
187		1,1,2-Trichloroethane			Yes	No						
188		0.000225	lb/ADUBT Pulp									
189		223275.8763	ADUBT/yr Pulp									
190		0.025118536	Ton /yr									
191		Xylenes			Yes	Yes						
192		0.00072	lb/ADUBT Pulp									
193		223275.8763	ADUBT/yr Pulp									
194		0.080379315	Ton /yr									
195		Zinc Comp.			No	No						
196		0	lb/ton RLS									
197		241500	RLS/yr									
198		0	Ton /yr									
199		Trichlorethylene			No	Yes						
200		0.000225	lb/ADUBT Pulp									
201		223275.8763	ADUBT/yr Pulp									
202		0.025118536	Ton /yr									
203		Formaldehyde			No	Yes						
204		0.00004	lb CHOH/hr	Average of two 1991 test by ESE								
205		8495	hr/yr									
206		0.0003398	Ton /yr									
207		Methyl Ethyl Ketone			No	Yes						
208		0.00893	lb MEK/hr	Average of four test sets from 1991-1995								
209		8495	hr/yr			No --->	Acetone	2.55	Ton/yr			
210		0.07586035	Ton /yr									
211		Chloroform			Yes	Yes						
212		0.0109	lb CHCl3/hr	1992 ESS test								
213		8495	hr/yr		1993 testing by Max F.			With Methanol				
214		0.0925955	Ton /yr		Total VOC	1.14880929	**Ton VOC/yr**	**46.52**	Method	3		
215						6.612765447	**lb VOC/day**	**267.77**				
216		Total HAPS										
217		46.79	Ton total HAPS/yr	Method	2		VGS MeOH/VOC =	0.975				
218		264.38	lb total HAPS/day									
219		% Methanol=	96.97%									
220												
221												
222					Bleaching Systems							
223												

Row #	Table 13	Bleaching Systems		
225	Year	VOC Ton/yr		CO Ton/yr
226	2003	178.17		
227	2004	177.84		
228	Baseline	178		
229	HCE blow heat recovey	-71.2		
230	Increase 8% no heat recovery project		14.24	
231	Increase 16.70% and recovery project		-41.47	25.12
232				

Row #

ATTACHMENT 1

Row #							
233	**Copy of AOR Calculations for VOC for Bleaching Systems**						
234	Methanol & VOC 2004	Miscellaneous Sources					
235	0.21	lb MeOH/ODUBT	Methanol Data Review SortII 9904				
236	200,948	ODUBT/yr					
237	21	Ton MeOH/yr					
238	Methanol	Hot Caustic Extraction Stage					Y
239	1.56	lb MeOH/ODUBT	Metco Tests March 2000				
240		Includes all HCE stage vents in the bleach plant					
241	200,948	ODUBT/yr					With Methanol
242	157	Ton MeOH/yr		Total VOC	178	Ton VOC/yr	178
243					1,024	lb VOC/day	1,024
244	Methanol	Total				Method	2
245	178	Total Ton MeOH/yr	Method	2			
246	1,024	lb MeOH/yr					
247							
248	Total HAPS						
249	178	Total HAPS/yr	Method	2			
250	1,024	lb HAPS/day					
251							

Row #										
252	**2004 Bleaching Systems Uncontrolled MeOH:**	2.44	**lb MeOH/ADMT**		**Pulping MeOH/VOC ratio:** 1.000		**CO/ODUBMT for bleaching:**	1.606	**CO/ADMT:**	2.21
253		**Production**	**Ton MeOH/yr**	**Ton VOC/yr**	**% Change from 1996**	**Ton/yr VOC change from 1996 without HCE heat recovery**	**CO Ton/yr**	**% Change from 1996**	**Ton/yr VOC change from 1996**	**Ton/yr VOC change from 2004**
254	1996	149,957	183	183	0.0%	0	120	0.0%	0	3
255	2003	144,976	177	177	-3.3%	-6	116	-3.3%	-4	-1
256	2004	145,883	178	178	-2.7%	-5	117	-2.7%	-3	0
257	Present PSD Limit	153,205	187	187	2.2%	4	123	2.2%	3	6
258	HCE Heat Rec. PSD Limit	162,000	197	197	8.0%	15	130	8.0%	10	13
259	Proposed PSD Limit	175,000	213	213	16.7%	31	141	16.7%	20	23
260										

Row #					
261	Evaporation and Chemical Recovery Process Operations				
262					
263	Sulfur Dioxide	Recovery Boiler			
264	2004 lb SSLS Captured/ADMT =		3394	Sulfur in SSLS =	6%
265		**Production**	**Potential SO2 from Recovery Boiler Ton SO2/yr**	**Change in potential SO2 from Recovery Boiler Ton SO2/yr compared to 1996**	**Change in potential SO2 from Recovery Boiler Ton SO2/yr compared to 2004**
266	1996	149,957	30,537	0	830
267	2003	144,976	29,523	-1,014	-185
268	2004	145,883	29,708	-830	0
269	Present PSD Limit	153,205	31,199	661	1,491
270	HCE Heat Rec. PSD Limit	162,000	32,990	2,452	3,282
271	Proposed PSD Limit	175,000	35,637	5,100	5,929
272					

Row #					
273	**2004 AOR VOC**	**Recovery Boiler**			
274				347.5	mill op. days/yr
275				0.95	MeOH/VOC ratio
276	**VOC from Methanol**				
277		0.33	lb/ODUBT 2004 tests		
278		145,883	ADMT bleached pulp produced/yr.		
279		200,948	ODT unbleached pulp produced.		
280		35	Ton VOC/yr.		
281		201	lb. VOC/day		
282					
283					

Row #												
284	Methanol				Uncontrolled							
285		Recovery Boiler Stack Tests 1991 - 2001:			49.928	lb MeOH/hr	13	tests	G:RWH/MACT Methanol/Methanol Data Review SortII 9904.xls.			
286					2.088	lb MeOH/ODUBT	13	tests	24.82	ODUBT/hr		
287		STACS testing [Cellunier - worst case grade] 2003			119.1	lb MeOH/hr	3	tests	595.68	ODUBT/day		
288					5.041	lb MeOH/ODUBT	3	tests	600.4415011	ADUBMT/day		
289		STACS testing 2004			49.9	lb MeOH/hr	1					
290					1.96	lb MeOH/ODUBT	1					

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Row #												
291				Weighted Average	62.07435294	lb MeOH/hr	17	tests	G:RWH/MACT Methanol/Methanol Data from 9/01 Tests.xls			
292					2.542764706	lb MeOH/ODUBT	17	tests				
293			2004	ODUBT/yr:	200948.2887							
294						Before Controls	0	Ton MeOH/yr	E991*E992/2000*(C15-C17)/C15			
295	Ton MeOH/yr	34		Method	1				recover hours before control/total recover hrs.			
296	lb/MeOH/day	204				After Controls	0.33	lb MeOH/ODUBT	Performance Test 2004		8.1666667	lb/hr
297							34.25373226	Ton MeOH/yr			196	
298	Total HAPS					Total for Year	34.25373226	Ton MeOH/yr			0.3266667	
299		Methanol										
300		34	T MeOH/yr									
301												
302		Acetaldehyde										
303		0.035	lb/ton RLS									
304		241500	RLS/yr									
305		4.22625	Ton /yr									
306		Benzene										
307		0.000052	lb/ton RLS									
308		241500	RLS/yr									
309		0.006279	Ton /yr									
310		Acrolein										
311		0.00135	lb/ton RLS									
312		241500	RLS/yr									
313		0.1630125	Ton /yr									
314		Arsenic										
315		0.0000034	lb/ton RLS									
316		241500	RLS/yr									
317		0.00041055	Ton /yr									
318		Chloromethane										
319		0.0047	lb/ton RLS									
320		241500	RLS/yr									
321		0.567525	Ton /yr									
322		Barium Compounds										
323		0.0000057	lb/ton RLS									
324		241500	RLS/yr									
325		0.000688275	Ton /yr									
326		Carbon Tetrachloride										
327		0.0015	lb/ton RLS									
328		241500	RLS/yr									
329		0.181125	Ton /yr									
330		Carbon Disulfide										
331		0.000073	lb/ton RLS									
332		241500	RLS/yr									
333		0.00881475	Ton /yr									
334		Chromium Comp.										
335		0.0000094	lb/ton RLS									
336		241500	RLS/yr									
337		0.00113505	Ton /yr									
338		Cobalt Comp.										
339		0.000084	lb/ton RLS									
340		241500	RLS/yr									
341		0.0095	Ton /yr									
342		Copper Comp.										
343		0.00016	lb/ton RLS									
344		241500	RLS/yr									
345		0.01932	Ton /yr									
346		Dichloromethane										
347		0.000061	lb/ton RLS									
348		241500	RLS/yr									
349		0.00736575	Ton /yr									
350		n-Hexane										
351		0	lb/ton RLS									
352		241500	RLS/yr									
353		0	Ton /yr									
354		Methyl Isobutyl Ketone										
355		0.0013	lb/ton RLS									
356		241500	RLS/yr									
357		0.156975	Ton /yr									
358		Lead Compounds										
359		0.000017	lb/ton RLS									
360		241500	RLS/yr									
361		0.00205275	Ton /yr									
362		Manganese Comp.										
363		0.0001	lb/ton RLS									

ATTACHMENT 1

Row #								
364		241500	RLS/yr					
365		0.012075	Ton /yr					
366		Mercury Comp.						
367		0	lb/ton RLS					
368		241500	RLS/yr					
369		0	Ton /yr					
370		Napthalene						
371		0.0029	lb/ton RLS					
372		241500	RLS/yr					
373		0.350175	Ton /yr					
374		Nickel Comp.						
375		0.000554865	lb/ton RLS					
376		241500	RLS/yr					
377		0.067	Ton /yr					
378		Phenol						
379		0.001	lb/ton RLS					
380		241500	RLS/yr					
381		0.12075	Ton /yr					
382		Styrene						
383		0.0018	lb/ton RLS					
384		241500	RLS/yr					
385		0.21735	Ton /yr					
386		1,2,4 Trichlorobenzene						
387		0.0049	lb/ton RLS					
388		241500	RLS/yr					
389		0.591675	Ton /yr					
390		Toluene						
391		0.0015	lb/ton RLS					
392		241500	RLS/yr					
393		0.181125	Ton /yr					
394		1,1,1-Trichloroethane						
395		0.0000042	lb/ton RLS					
396		241500	RLS/yr					
397		0.00050715	Ton /yr					
398		1,1,2-Trichloroethane						
399		0.0034	lb/ton RLS					
400		241500	RLS/yr					
401		0.41055	Ton /yr					
402		Xylene						
403		0.003	lb/ton RLS					
404		241500	RLS/yr					
405		0.36225	Ton /yr					
406		Zinc Comp.						
407		0.012	lb/ton RLS					
408		241500	RLS/yr					
409		1.449	Ton /yr					
410		Trichlorethylene						
411		0.0032	lb/ton RLS					
412		241500	RLS/yr					
413		0.3864	Ton /yr					
414		Formaldehyde						
415		0.000275	lb CHOH/hr	Average of two 1991 test by ESE				
416		8071.97	hr/yr					
417		0.002219792	Ton /yr					
418		Methyl Ethyl Ketone						
419		0.072	lb CHOH/hr	Average of four test sets from 1991-1995				
420		8071.97	hr/yr					
421		0.58118184	Ton /yr					
422		Chloroform						
423		0.00069	lb CHCl3/hr	1993 ESS test				
424		8071.97	hr/yr		1993 testing by Max F.			With Methanol
425		0.005569659	Ton /yr		Total VOC	8.12	Ton VOC/yr	42.37
426		Total HAPS						
427		44.34201433	Ton total HAPS/yr	Method				
428		263.6799552	lb total HAPS/day		2		VGS MeOH/VOC =	0.81
429		% Methanol=	0.772489315					
430								
431	2004 AOR							
432	EU ID 018	Miscellaneous Utilities Area Emissions						
433		No data and no significant emissions expected if not listed.						
434		Methanol						
435		0.2172	lb MeOH/ODUBT	Methanol Data Review SortII 9904				
436		200948.2887	ODUBT/yr					

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Row #							
437		21.82298415	Ton MeOH/yr	Method	2		
438		129.7704574	lb MeOH/day				
439					Total VOC	21.82298415	Ton VOC/yr
440		Total HAPS				129.7704574	lb VOC/day
441		21.82298415	Ton Total HAPs/yr	Method	2		
442		129.7704574	lb Total HAPs/day				
443							
444	2004 AOR Total VOC Evaps & Chem. Rec. Area Ton/yr	56.72	0.778	lb VOC/ADMT			
445							
446	Total VOC Evaporation & Chemical Recovery	Production	Ton VOC/yr	Ton VOC/yr Change from 1996			
447	1996	149,957	58	0			
448	2003	144,976	56	-2			
449	2004	145,883	57	-2			
450	Present PSD Limit	153,205	60	1			
451	HCE Heat Rec. PSD Limit	162,000	63	5			
452	Proposed PSD Limit	175,000	68	10			
453							
454							
455	Wastewater Treatment System						
456	Table 13	VOC Ton/yr					
457	2003	76.89					
458	2004	55.64					
459	Baseline	66.26					
460	Increase 8%		5.301				
461	Increase 16.70%		11.065				
462							
463	EU ID 010	Wastewater Collection and Treatment					
464	AOR 2004	No data and no significant emissions expected if not listed.					
465		Methanol					
466		0.45	lb MeOH/ODUBT	Water 9 model* 2004	Method	2	
467		200,948	ODUBT/yr				
468		45	Ton MeOH/yr		*2003 Source Testing and Consulting Services		
469		248	lb MeOH/day		Used VGS hours 0.92 lb MeOH/ODUBT before control & 0.24 lb MeOH/ODUBT after control.		
470							
471		Benzene					
472		0	ND [10]	NCASI Bleach Sulfite Form R Handbook			
473		Chloroform			Method	2	
474		52	g/ADUBMT	BAT Chloroform summary			
475		0.89	% volatized NCASI Form R Handbook				
476		46.28	g/ADUBMT Volatized				
477		202554.5462	ADUBMT/yr				
478		10.33313977	Ton CHCl3/yr				
479		56.61994394	lb CHCl3/yr				
480							
481		Chlormethane					
482		0	ND	NCASI Bleach Sulfite Form R Handbook			
483		Cresol					
484		85.7	ppb WTS influent	NCASI Bleach Sulfite Form R Handbook			
485		0.0005	% volatized NCASI Form R Handbook				
486		36498.5265	Mlb/yr effluent				
487		0.007819809	Ton Cresol/yr				
488		Dichloromethane					
489		0	ND	NCASI Bleach Sulfite Form R Handbook			
490		Formaldehyde					
491		1.39	ppm in effluent to the ASB		2000 TRI calculations		
492		0.002	% volatized NCASI Form R Handbook				
493		36498.5265	Mlb/yr effluent				
494		0.050732952	Ton CHOH/yr				
495		N-Hexane					
496		0	No mill or pertinent NCASI data				
497		MEK					
498		0.042	ppm in effluent to the ASB				
499		0.048	% volatized NCASI Form R Handbook				
500		36498.5265	Mlb/yr effluent				

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Row #							
501		0.036790515	Ton MEK/yr				
502		MIBK					
503		0	ND[50]	NCASI Bleach Sulfite Form R Handbook			
504		Napthalene					
505		0	No mill or pertinent NCASI data				
506		Pentachlorophenol					
507		1.1	ppb in WTS discharg	Mill data collected in 2001.			
508		0.1	ppb in WTS influent	Mill data collected in 2001.			
509		0	Ton/yr volatized				
510		Phenol					
511		0	No volatilization	NCASI Form R Handboo	Total VOC		
512		Styrene					
513		0	No mill or pertinent NCASI data				
514		Tetrachloroethylene					
515		0	ND[10]	NCASI Bleach Sulfite Form R Handbook			
516		Toluene					
517		0	ND[10]	NCASI Bleach Sulfite Form R Handbook			
518							
519		Total HAPS				VOC = HAP for these WWT compounds	
520		55.64	Ton HAPS/yr	0.81257842	Methanol		
521		320	lb/day	Method	2		
522							

Row #		VOC lb/ADMT =	0.763	
524	Total VOC Wastewater Treatment Systems	Production	Ton VOC/yr	Ton VOC/yr Change from 1996
525	1996	149,957	57	-1
526	2003	0	0	-58
527	2004	145,883	56	-3
528	Present PSD Limit	153,205	58	0
529	*HCE Heat Rec. PSD Limit*	*162,000*	62	3
530	Proposed PSD Limit	175,000	67	8

531

532 **Power and Steam Production Operations**

533

534

Row #	2004 AOR Power Boiler Calculations											
536	Parameter		Value	Reference Source								
537												
538								Operating Hours				
539	Operating Hours (hrs/yr)					op. days / yr	Quarter	CEM AP	CEM Rec	AP days	Rec days	
540	No. 1 Power Boiler		8084.39	Dynamic Reporter "Utilities Equipment Uptime"		336.8495833	1	1895	1660.1	78.95833333	69.170833	
541	No. 2 Power Boiler		8132.87	Dynamic Reporter "Utilities Equipment Uptime"		338.8695833	2	2184	2096.8	91	87.366667	
542	No. 3 Power Boiler		8180.7	Dynamic Reporter "Utilities Equipment Uptime"		340.8625	3	2208	2178.9	92	90.7875	
543	No. 8 Power Boiler on Oil		0	Dynamic Reporter "Utilities Equipment Uptime"		0	4	2208	2139.8	92	89.158333	
544	No. 8 Power Boiler on Diesel		0	Dynamic Reporter "Utilities Equipment Uptime"		0	Sum	8495	8075.6	353.9583333	336.48333	
545	Portable Generators on Diesel		0	Dates No. 3 TG was down:		0		353.9583333	336.4833333			
546	Recovery Boiler		8071.97	Quarterly CEM Reports - Same as Dynamic Rpt."Utilities Equipment Uptime		336.3320833	336.3320833	days	Mill Mach.Op. Days:		347.452	
547	VGS		8495	Quarterly CEM Reports		353.9583333	353.9583333	days	Mill Mach.Op. Hours:		8338.848	
548	Evap. MeOH Condenser Uptime		8339.1	Semi-annual reports	Startup on April 15, 2002	347.4625	3969	4370.1				
549	VGS MeOH Condenser Uptime		8339.1	Semi-annual reports	Startup on April 15, 2002	347.4625	3969	4370.1				
550												
551	Fuel Oil - Total Metered (BBL/yr)		249324	249324								
552	No. 1 Power Boiler		121703	Dynamic Reporter "Env - 1C - Morning Utilities Report"								
553	No. 2 Power Boiler		28699	Dynamic Reporter "Env - 1C - Morning Utilities Report"								
554	No. 3 Power Boiler	197559	47157	Dynamic Reporter "Env - 1C - Morning Utilities Report"								
555	No. 8 Power Boiler on Oil	197323	0	Dynamic Reporter "Env - 1C - Morning Utilities Report"								
556	No. 8 Power Boiler on Diesel		0	Dynamic Reporter "Env - 1C - Morning Utilities Report"								
557	Portable Generators on Diesel		0	Utilities cost statement & Accounting Worksheet			0	$/yr	1.2	$/gal diesel		
558	Recovery Boiler	51240	51765	Dynamic Reporter "Env - 1C - Morning Utilities Report"								
559							Total Oil					
560	Fuel Oil - Total Adjusted to Inv. (BBL/yr)		242651	"STATS & COSTS" Report under "Fuel Oil Usage - BBLs" "Total"			10191.342	1000 gal./yr	Oil			
561	No. 1 Power Boiler		118445.6958	Calculated		0.488131909	1599293.329	MM BTU/yr	Oil	19615.83333	BTU/lb	
562	No. 2 Power Boiler		27930.88932	Calculated		0.11510725	81.530736	MM lb/yr	Oil			
563	No. 3 Power Boiler		45894.87256	Calculated		0.189139433	18300	BTU/lb	Oil			
564	No. 8 Power Boiler on Oil		0	Calculated			1492012.469	MM BTU/yr Ck.	Oil			
565	No. 8 Power Boiler on Diesel		0	Calculated			156.9266667	MMBTU/1000 gal	Oil			
566	Portable Generators on Diesel		0									
567	Recovery Boiler		50379.54234	Calculated	242651	Fuel Oil Sum Check						

ATTACHMENT 1

Row #	A	B	C	D	E	F	G	H	I	J	K
568					2115.940778						
569	Fuel Oil [# 6] Analysis										
570	% Sulfur		1.497083333	Fuel Oil Analysis - Average from below							
571	Btu/gal		156926.6667	Fuel Oil Analysis - Average from below							
572							from Dynamic Reporter				
573	Steam Production (1,000 lb/yr of 1000 BTU Steam)		5188968.157	Total Steam - Calculated		% of total steam	k lb steam / hr	k lb 1000 BTU steam/l	As Is Steam	BTU/lb Steam	% of cap
574	No. 1 Power Boiler		537416.88	Dynamic Reporter "Env - 1C - Morning utilities Report"		0.103569123	59.43305556	66.47587264	480480	1118.5	0.4952755
575	No. 2 Power Boiler		625357.824	Dynamic Reporter "Env - 1C - Morning utilities Report"		0.120516797	68.74621136	76.89263741	559104	1118.5	0.5728851
576	No. 3 Power Boiler		840324.576	Dynamic Reporter "Env - 1C - Morning utilities Report"		0.161944446	91.83761781	102.7203755	751296	1118.5	0.6802787
577	No. 8 Power Boiler on Oil		0	Dynamic Reporter "Env - 1C - Morning utilities Report"		0		0			
578	No. 8 Power Boiler on Diesel		0	Dynamic Reporter "Env - 1C - Morning utilities Report"		0		0			
579	Recovery Boiler		3185868.877	Dynamic Reporter "Env - 1C - Morning utilities Report"		0.613969633	352.8680762	394.6829433	3083808	1033.09573	0.9001737
580						1	572.8849609	640.7718288	4874688		
581	Bark and Knots - Mtons (OD)/yr						1185	BTU/lb Steam			
582	Purchased Bark		39486	"STATS & COSTS" Report		Total Power Boilers	220.0168847				
583	Self-Produced Bark		82911	"STATS & COSTS" Report							
584	Reclaim - Knots		0	"STATS & COSTS" Report							
585	Total hog fuel Mton/yr (OD)		122397								
586	Total hog fuel wet ton/yr		236698.6195	calculation		0.57	Bark % OD				
587	Total hog fuel MMBTU/yr		2366986.195	calculation	5000 BTU/wet lb. bark						
588	Total hog fuel ODT/yr		134918.2131								
589											
590	PM Emission Rate (lbs/hr)										
591	A Scrubber - No. 1 and 2 Power Boilers		43.11566667	Stack Test - Power Boiler Scrubber A PM Data Below							
592	B Scrubber - No. 3 Power Boiler		34.32666667	Stack Test - Power Boiler Scrubber B PM Data Below							
593	Recovery Boiler		23.6805	Stack Test - Recovery Boiler PM Data Below							
594	Rec Boiler - Vol. Flow Rate (dscfm)		121095.75	Stack Test - Recovery Boiler PM Data Below							
595	SO2 Conc. (ppm)										
596	Recovery Boiler		163.4262295	Dynamic Reporter "Env - 3I - Air Report - Recovery" [with SD (March 1-20) extraneous readings removed]							
597	VGS		12	Dynamic Reporter "Env - 3H - Air Report - Acid Plant"							
598											
599	Pulp Production - Tons (ADUBT)/yr		223275.8763	Calculation Below							
600	Pulp Production - Tons (ADUBT)/day		642.6092706								
601	Pulp Production - Tons (ODUBT)/yr		200948.2887								
602	Pulp Production - Tons (ADMT)/yr		145883	MT Bleached [net] production							
603	Pulp Production - Tons (ADT)/yr		160806.8309	T Bleached [net] production							
604	Pulp Production - Tons (ADMT)/day		419.86519	MT Bleached [net] production							
605	Pulp Mil Op. Days/yr.		347.452								
606	Recovery Boiler SSL Burned Tons SSLS/yr		241500								
607	ASB Effluent [E3] flow rate [Env 2A Flow Report]		4373.7	Mgal/yr	11.95	mgd					
608	ASB Effluent [E3] flow rate		36498.5265	Mlb/yr							
609	Digesters/Year		6838	no. /year	Stats & Costs page 25						
610	SSL Burned/Year		483	Million OD lb/yr	483	Env. 1C					
611	Chip Usage		427309	MT/yr	Stats & Costs page 8						
612											
613											
614											
615	Operating Hours										
616	Emission Unit	Total (hrs/yr)	Total (Equiv. Days/yr)								
617	No. 1 Power Boiler	8084.39	336.8495833								
618	No. 2 Power Boiler	8132.87	338.8695833								
619	No. 3 Power Boiler	8180.7	340.8625								
620	No. 8 Power Boiler on Oil	0	0								
621	No. 8 Power Boiler on Dies	0	0								
622	Recovery Boiler	8071.97	336.3320833								
623	SO2 VGS System	8495	353.9583333	And Molten S tank							
624	Mill Wide	8338.848	347.452								
625											
626											
627											
628	Fuel Oil - Usage										
629	Units	No. 1 Power Boiler	No. 2 Power Boiler	No. 3 Power Boiler	PB Total	No. 8 Power Boiler on	Recovery Boiler	Total			
630	Barrels (BBL)/yr (a)										
631	BBL/yr (Adjusted) (b)	118445.6958	27930.88932	45894.87256	192271.4577	0	50379.54234	242651			
632	1000 gal/yr	4974.719222	1173.097351	1927.584648	8075.401222	0	2115.940778	10191.342			
633	Heat Input MMBTU/yr	780666.1052	184090.257	302489.4335	1267245.796		332047.5332	1599293.329			
634	42	gal/bbl									
635	1000 gal/day (c)	14.76836983	3.461795951	5.655021153			6.291224903	30.17641183			
636											
637	Example Calculations:										
638	BBL/yr (Adjusted)	= [Barrels (No. 1 PB)] x [Barrels (Total-Adj)] / [Barrels (Total)]									
639	1000 gal/yr	= [Barrels (No. 1 PB Adj)] x [42 gal/barrel] / 1000									
640	1000 gal/day	= [____1000 gal/yr] / [Days of Operation (days/yr)]									

ATTACHMENT 1

Row #												
641												
642	Notes:											
643	(a) Fuel Usage in BBL/yr for each boiler is taken from the Mikon Reports "Power Boiler Summary" and "Recovery Boiler Summary."											
644	(b) Total Adjusted Fuel Usage is taken from the "STATS & COSTS" Report under "Fuel Oil Usage - BBLS" "Year Actual" "Total."											
645	Each boiler's Adjusted Fuel Usage is back calculated from this "Total" by a ratio.											
646	(c) Used as Ozone Season Rate (gal/day). The Ozone Season applies from May 31 to August 31.											
647												
648												
649	Fuel Oil Analysis -	Report Year										
650		Colonial Oil Industries No. 6 Oil			No. 2 Oil							
651	Month	% S	Btu/gal	% Nitrogen	% S	Btu/gal	% Nitrogen					
652	January	1.92	158220									
653		1.64	158414									
654	February	1.68	155799									
655		1.59	158006									
656	March	1.44	155879									
657		2.06	153627									
658	April	2.06	155413									
659		1.17	158499									
660	May	1.49	155830									
661		1.52	156982									
862	June	1.39	157762									
663		1.59	156942									
664	July	1.41	156157									
665		1.37	156718									
666	August	1.61	155043									
667		1.14	160014									
668	September	1.44	155555									
669		1.43	156984									
670	October	1.13	160279									
671		1.26	159804									
672	November	1.35	156984									
673		1.3	154572									
674	December	1.4	156186									
675		1.54	156571									
676	Average	1.497083333	156926.6667									
677		BTU/1000 gal.	156926666.7									
678		mmBTU/1000 gal.	156.9266667									
679												
680												
681												
682												
683			Report Year Boiler Steam Production [1000 BTU Steam]			MMBTU/hr	MMBTU/hr					
684	Boiler	Max Cap (1000 lb/hr) As	1,000 lb/yr	1,000 lb/hr	1,000 lb/day	Permitted Oil	Permitted bark	Oil Spec. Efficiency	Bark Spec. Efficiency	Actual Op. % of Cap.		
685	No. 1 Power Boiler	120	537416.88	66.47587264	1595.420943	185		0.648648649		0.467481523		
686	No. 2 Power Boiler	120	625357.824	76.89263741	1845.423298	184	218	0.652173913	0.550458716	0.540735847		
687	No. 3 Power Boiler	135	840324.576	102.7203755	2465.289012	207	245	0.652173913	0.551020408	0.642102676		
688	No. 8 Power Boiler on Oil		0									
689	No. 8 Power Boiler on Diesel		0									
690	Recovery Boiler	392	3185868.877	394.6829433	9472.390638		653.1		0.600214362	0.795964768		
691			*2905909.2*	*360*								
692		PBs	2003099.28	246.0888856								
693	Example Calculation:			312.0181892								
694	1,000 lbs/hr	= [_____ 1,000 lbs/yr] / [Hours of Oper (hrs/yr)]			Conversion to 1000 BTU Steam:		1.185	PBs	1.385	0.855595668		
695	1,000 lbs/day	= [_____ 1,000 lbs/yr] / [Days of Oper (days/yr)]			[BTU 1000 lb/BTU actual lb]		1.264935689	Rec	1.44	0.878427562		
696												
697	Note:						bbl/yr	Heat Input MMBTU/yr	%of Total PB Input			
698	* Steam Production (1,000 lbs/yr) taken from the Mikon Reports "Power Boiler Summary" and "Recovery Boiler Summary"					Total Oil usage	242651	1599293.329				
699						Power Boiler Oil Usage	192271.4577	1267245.796	0.377485195			
700	Heat Output (1000 Btu/lb)											
701	Fuel Source	Boiler Steam Eff.	No. 2 Power Boiler	No. 3 Power Boiler	No. 2 & 3		ODT/yr	Heat Input MMBTU/yr				
702	Total from Steam	1	76892.63741	102720.3755	179613.0129	Bark via Steam *	208982.8366	2089828.366	0.622514805			
703	- Oil	0.65	14712.96935	24034.38969	38747.35905	Bark via weightometer	236698.6195	2366986.195				
704	- Bark by Diff.	0.55	62179.66805	78685.98583	140865.6539							
705						Total PB Heat Input	MMBTU/yr	3357074.161	1			
706	Example Calculation:											
707	Total (1000 Btu/hr)	= [Steam Production (1000 lbs/hr)] x [1000 Btu/lb (Steam)]				* used for AOR						
708	Oil (1000 Btu/hr)	= [Oil Usage No. 2 PB (1000 gal/yr)] x [Heat Cap (Btu/gal)] x [Boiler Eff (Oil)] / [Hours of Oper No. 2 PB (hrs/yr)]										
709	Bark (1000 Btu/hr)	= [Heat Output Total] - [Heat Output from Oil]										
710												
711	Bark - Usage (Steam Meter Basis)											
712	Units	No. 2 Power Boiler	No. 3 Power Boiler	Total	Total Hogfuel ODMT	Note:						
713	Lbs (Bark-wet)/hr	22610.78838	28613.08575	51223.87414	Year	5000	Btu/lb Bark-wet					

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Row #												
714	Tons (Bark-wet)/yr	91945.30126	117037.5353	208982.8366	108065.8607	8771.929825	BTU/lb OD Bark					
715		271.3294606	343.3570291	Value used	Day	0.57	OD lb bark/lb Bark-wet	467.0429672	ODT bark/day			
716		0.439965802	0.560034198		318.9010346	10	mm BTU/Ton Bark-wet	423.6986003	ODMT/day			
717	MMBTU Heat Input	919453.0126	1170375.353	2089828.366								
718												
719	Bark Usage Analysis (Steam Meter vs. Weightometer - Bark and Chip)											
720			Bark Weightometer1	Chip Weightometer Basi	Chips Used ODMT/yr	Chip Prod. ODMT/yr	0.55	Chip % OD				
721	Purchased Bark	MTons (OD)/yr	39486	39486								
722	Self-Produced Bark	MTons (OD)/yr 2 and 3	82911	85532.76157	427309	417601.13	from Cost & Stats Rept.	p.8 of 35				
723	Reclaim - Knots	MTons (OD)/yr	0	0		ODT/yr	inventory adjusted.					
724	Total Bark	MTons (OD)/yr	122397	125018.7616		460321.7256	37144.35	jan p.26	beginning chip inventory			
725	Notes:					Wet T/yr	27436.48	dec p.26	ending chip inventory			
726	1 Bark Weightometer values taken from "STATS & COSTS" Report under "Purchased Bark", "Self-Produced Bark", and "Knots."					836948.592						
727	1 Self-Produced Bark from Bark Weightometer.					2364.539871						
728	2 Self-Produced Bark from Chip Weightometer at bark =			0.17	of chips	Wet T/day						
729												
730			Bark Weightometer	Chip Weightometer	Steam Meter							
731	% OD		0.57	0.57								
732	Conversion Factor	Tons/Mtons	1.1023	1.1023								
733	Total Bark	Tons (Bark-Wet)/yr	236698.6195	241768.7384	208982.8366							
734		ODT/day	396.9746799		Value Used							
735	Bark Usage Difference from Steam meter Calc.		-27715.7829	-32785.9018								
736		% Difference	-0.132622293	-0.156883227								
737												
738		[Steam Meter vs. Weight	= Tons (Bark-wet)/yr	[Steam Meter - Weightometer]								
739												
740		Stack Tests - Particulate Matter (PM) Emissions										
741												
742												
743	A Scrubber Stack Tests [No. 1 & 2 PB]											
744		PM Emission Rate [lbs (PM)/hr]										
745	Date	Run	Test Average	Volume [dscf/m]	Volume [dscf/m]	Steam Prod. Klb/hr	% of Capacity	O2 [%V,dry]	NOX [ppmV, dry]	SO2 [ppmV, dry	CO [ppmV,dry]	
746	38148	30.984		92695.6		195.246	0.813525	11.4	79.7	3.7	255.7	
747	38148	41.218		100362.6		197.5158	0.8229825	12.3	86.3	4.1	175.7	
748	38148	57.145	43.11566667	90347	94468.4	197.3	0.822083333	11.8	79.4	3.7	248.6	
749												
750												
751												
752												
753												
754												
755												
756		43.11566667	43.11566667	94468.4	94468.4	196.6872667	0.819530278	11.83333333	81.8	3.833333333	226.66667	
757												
758												
759	B Scrubber Stack Tests [PB # 3]											
760		PM Emission Rate [lbs (PM)/hr]										
761	Date	Run	Test Average	Volume [dscf/m]	Volume [dscf/m]	Steam Prod. Klb/hr	% of Capacity	O2 [%V,dry]	NOX [ppmV, dry]	SO2 [ppmV, dry	CO [ppmV,dry]	
762	38147	20.9		98106.4		122.164	0.904918519	11.5	53.8	0.8	133.3	
763	38147	47.64		89716.4		123	0.911111111	12.4	62.1	0.3	115.8	
764	38147	34.44	34.32666667	90837.6	92886.8	117.333	0.869133333	12.4	63.7	0.4	150.6	
765												
766												
767												
768												
769												
770												
771	Average	34.32666667	34.32666667	92886.8	92886.8	120.8323333	0.895054321	12.1	59.86666667	0.5	133.23333	
772												
773												
774	Recovery Boiler Stack Tests											
775		Vol Flow Rate [dscfm]		PM Emission Rate [lbs (PM)/hr]								
776	Date	Run	Test Average	Run	Test Average	SSLS lb/hr	% of Capacity	Steam kpph	O2 [%V,dry]	NOX [ppmV, dry	SO2 [ppmV,	CO [ppmV,dr
777	38131	114266.4		21.151		65111	0.930157143	375	4.2	595.5	195.8	1.3
778	38131	119454.9		19.75		69665	0.995214286	399	3.9	615.8	207.8	1.1
779	38131	119059.2		23.102		66210	0.945857143	354	3.9	604.1	219.9	3.2
780	38132	124031		24.97		68046	0.972085714	389				
781	38132	124244.8		22.91		70377	1.005385714	398				
782	38132	125518.2	121095.75	30.2	23.6805	68557	0.979385714	392				
783												
784												
785												
786	Average	121095.75	121095.75	23.6805	23.6805	67994.33333	0.971347619	384.5	4	605.1333333	207.83333	1.86666667

ATTACHMENT 1

Row #												
787												
788												
789												
790												
791	**EU ID 001**	**No. 1 Power Boiler - Oil Fired**										
792												
793	CO											
794	lbs (CO)/1000 gal (Fuel Oil)		5	Emission Factor from AP-42, Table 1.3-1[9/98].		226.6666667	ppmV CO 2004	385	dscf/mole			
795	1000 gal/yr [fuel oil]		4974.719222			94468.4	dscf/m flue gas	28	lb CO/mole CO			
796	Op. Days/yr		336.8495833			21.41283733	dscf/min CO	93.43783564	lb CO/hr			
797	Tons (CO)/yr		12.43679806					377.693952	T CO/yr			
798	lbs (CO)/day		73.84184913		Method Code	3		2242.508055	lb CO/day			
799	Example Calculation:											
800	Tons (CO)/yr	= [Fuel Oil Usage (1000 gal/yr)] x [lbs (CO)/1000 gal (Fuel Oil)] / [2000 lbs/ton]										
801	lbs (CO)/day	= [Ozone Rate (1000 gal/day)] x [lbs (CO)/1000 gal (Fuel Oil)]										
802												
803	NOx					A Scrubber						
804	lbs (NOx)/1000 gal (Fuel Oil)		47	Emission Factor from AP-42, Table 1.3-1[9/98].		81.8	ppmV NOX 2004	385	dscf/mole	Note for 2005		
805	1000 gal/yr [fuel oil]		4974.719222			94468.4	dscf/m flue gas	46	lb NO2/mole NO2	Use 95% NO	30	NO lb/mole
806	Op. Days/yr		336.8495833			7.72751512	dscf/min NOX	55.39725125	lb NOX/hr	30.8	instead of	46
807	Tons (NOx)/yr		116.9059017					223.926492	T NOX/yr			
808	lbs (NOx)/day		694.1133818		Method Code	3		1329.53403	lb NOX/day			
809	Example Calculation:											
810	Tons (NOx)/yr	= [Fuel Oil Usage (1000 gal/yr)] x [lbs (NOx)/1000 gal (Fuel Oil)] / [2000 lbs/ton]										
811	lbs (NOx)/day	= [Ozone Rate (1000 gal/day)] x [lbs (NOx)/1000 gal (Fuel Oil)]										
812												
813	Lead (H110)											
814	lbs (Pb)/hr [A scrubber - No. 1 & 2 PBs]		0.07	Average from 06-14-95 Stack Test Data.								
815	Tons (Pb)/yr [A scrubber (No. 1 & 2 PBs)]		0.28295365									
816	Tons (Pb)/yr [No. 1 PB using ratio of Oil Usage]		0.22896177									
817	lbs (Pb)/day		1.359430327		Method Code	2						
818	Example Calculation:											
819	Tons (Pb)/yr [A scrubber - No. 1 & 2 PBs]		= [lbs (Pb)/hr from A scrubber] x [Hours of Oper (hrs/yr)] / [2000 lbs/ton]									
820	Tons (Pb)/yr [No. 1 PB using ratio of Oil Usage]		= [Tons (Pb)/yr A scrubber] x [Oil Usage(1000 gal/yr) No1PB] / [Oil Usage(1000 gal/yr) No1&2PB]									
821	lbs (Pb)/day		= [Tons (Pb)/yr (No.1 PB using ratio of Oil)] x [2000 lbs/ton] / [Days of Operation (days/yr)]									
822												
823	SO2											
824	A scrubber efficiency for SO2 (%)		0.9		A Scrubber pH =	6	Env - 3K - Air Report - Power Boilers					
825	Density of Oil (lbs/gal)		8									
826	Tons (SO2)/yr		59.58055389		Method Code	2						
827	lbs (SO2)/day		353.7516852									
828	Example Calculation:											
829	Tons (SO2)/yr	= [Oil Usage(1000 gal/yr)] x Density of Oil(lb/gal) x [%S/100] x [MW(SO2)/MW(S)] x [1 - A scrub. eff SO2(%)] / [2000 lbs/ton]										
830	lbs (SO2)/day	= [Ozone Rate (1000 gal/day)] x Density of Oil (lbs/gal) x [%S / 100] x [MW (SO2) /MW (S)] x [1 - A scrubber eff SO2 (%)]										
831												
832	VOC											
833	lbs (VOC)/1000 gal (Fuel Oil)		0.76	Emission Factor from AP-42, Table 1.3-3 [9/98].			Utility Boiler >100MMBTU/hr					
834	Tons (VOC)/yr		1.890393305									
835	lbs (VOC)/day		11.22396107		Method Code	3						
836	Example Calculation:											
837	Tons (VOC)/yr	= [Oil Usage (1000 gal/yr)] x [lbs (VOC)/1000 gal (Fuel Oil)] / [2000 lbs/ton]										
838	lbs (VOC)/day	= [Ozone Rate (1000 gal/day)] x [lbs (VOC)/1000 gal (Fuel Oil)]										
839												
840	PM											
841	lbs (PM)/1000 gal (Fuel Oil)		16.97819583	Emission Factor from AP-42, Table 1.3-1 [9/98].		[(9.19) S + 3.22)]		9.319939512	A Scrubber Annual Op./test ratio			
842	Sulfur Content (% by weight)		1.497083333		Table 1.3-5 [9/98]	8.34[1.12S + .37] = 9.34S + 3.09			0.651690722			
843	A scrubber efficiency for PM (%)		0.8									
844	Tons (PM)/yr		8.446175718		40.95177418	A actual x 1999 PM Ratio #1PB/A Scrubber:*		0.360561056				
845	lbs (PM)/day		50.14805501		243.1457612							
846	Example Calculation:					Method Code	2					
847	Tons (PM)/yr	= [Oil Usage (1000 gal/yr)] x [lbs (PM)/1000 gal (Oil)] x [1 - A scrubber eff PM] / [2000 lbs/ton]				=[Actual A Scrubber PM (lb/hr)] x [1999 test ratio (.36)] x [op hr/yr] / 2000						
848	lbs (PM)/day	= [Ozone Rate (1000 gal/day)] x [lbs (PM)/1000 gal (Oil)] x [1 - A scrubber eff PM]				* in 1999 separate boiler emissions tests were run.						
849												
850	PM10											
851	lbs (PM10)/1000 gal (Fuel Oil)		14.675078	Emission Factor from AP-42, Table 1.3-5.		[7.17 x (1.12 S + .37)]						
852	Sulfur Content (% by weight)		1.497083333					PM10/PMTotal				
853	Tons (PM10)/yr	[efficiency is in the calc.]	7.300439262	Based on PM above & PM10/PM em. fact. ratio		35.39660434	0.864348494	0.85971223				
854	lbs (PM10)/day		43.34539583			210.1626726						
855	Example Calculation:											
856	Tons (PM10)/yr	= [Oil Usage (1000 gal/yr)] x [lbs (PM10)/1000 gal (Oil)] x [1 - A scrubber eff PM] / [2000 lbs/ton]				Method Code	4					
857	lbs (PM10)/day	= [Ozone Rate (1000 gal/day)] x [lbs (PM10)/1000 gal (Oil)] x [1 - A scrubber eff PM]										
858												
859	Total HAPS											

ATTACHMENT 1

Row #											
860						Using No. 1 PB (max) hr/yr					
861		Methanol		0.75	lb/hr total for all PB	6063.2925	lb/yr	0.030173397	lb/ODUBT		
862				1991 test by Rayonier [M. Folsom]							
863											
864							HAPS [lb/yr]				
865		0.030173397	lb MeOH/ODUT	from all power boilers	G:RWH/MACT methanol/Methanol Data Review SortII 9904.xls.			Oil	Oil	Oil	Oil
866		200948.2887	ODUBT/yr				All PB Oil Lb/yr	No. 1 PB lb/yr	No. 2 PB lb/yr	No. 3 PB lb/yr	Rec lb/yr
867		3.03164625	T MeOH/yr All PB	No power boiler can be above the 5 ton/yr threshold		2288.803154	2288.803154	1409.979855	332.4898472	546.3334514	0
868			from Oil & Bark		% of Total Heat Input	% of Oil Heat Input					
869		780666.1052	Heat input # 1 PB on oil		0.232543598	0.488131909					
870		184090.257	Heat input # 2 PB on oil		0.054836518	0.11510725					
871		919453.0126	Heat input # 2 PB on bark		0.273885225						
872		302489.4335	Heat input # 3 PB on oil		0.090105079	0.189139433					
873		1170375.353	Heat input # 3 PB on bark		0.348629579						
874		1267245.796	Total Heat input from Oil for PBs								
875		3357074.161	Total Heat input to power boilers (oil & bark)		1						
876	Ton HAPS/yr	1599293.329	Total Heat Input from Oil total All boilers			1					
877	No. 1 PB [Oil fired only]	332047.5332	Heat input Recovery Boiler on Oil			0.207621408					
878		Methanol			No. 1 PB MeOH/VOC =	0.372932937					
879	0.704989928	1.144401577	Ton MeOH/yr	All power boiler total from Oil							
880		Benzene			0.00021	lb Benzene/1000 gal.					
881		1.3382E-06	lb/MMBTU from Oil	NCASI factor	1.3382E-06	lb/MMBTU oil					
882		1599293.329	MMBTU/yr from Oil	All power & recovery oil usage basis							
883	0.000522346	0.001070091	Ton Benzene/yr	All power & recovery oil usage basis			2.14018182	1.044691037	0.246350444	0.404792776	0.4443476
884		Acrolein									
885		0.01	ppm in fuel oil - NCASI								
886		81.530736	MM lb/yr Oil								
887	0.000198989	0.000407654	Ton /yr	All power & recovery oil usage basis			0.81530736	0.397977538	0.093847788	0.154206772	0.1692753
888		Arsenic									
889		0.00132	lb/1000 gal.oil - NCASI								
890		10191.342	1000 gal. Oil /yr								
891	0.003283315	0.006726286	Ton /yr	All power & recovery oil usage basis			13.45257144	6.566629374	1.548488504	2.544411735	2.7930418
892		Antimony Comp.									
893		0.01	ppm in fuel oil - NCASI								
894		81.530736	MM lb/yr Oil								
895	0.000198989	0.000407654	Ton /yr	All power & recovery oil usage basis			0.81530736	0.397977538	0.093847788	0.154206772	0.1692753
896		Barium Compounds									
897		0.00257	lb/1000 gal.oil - NCASI								
898		10191.342	1000 gal. Oil /yr								
899	0.006392514	0.013095874	Ton /yr	All power & recovery oil usage basis			26.19174894	12.7850284	3.014860193	4.953892544	5.4379678
900		Beryllium Comp.									
901		0.08	ppm in fuel oil - NCASI								
902		81.530736	MM lb/yr Oil								
903	0.00159191	0.003261229	Ton /yr	All power & recovery oil usage basis			6.52245888	3.183820302	0.750782305	1.233654175	1.3542021
904		Cadmium Comp.									
905		0.3	ppm in fuel oil - NCASI								
906		81.530736	MM lb/yr Oil								
907	0.005969663	0.01222961	Ton /yr	All power & recovery oil usage basis			24.4592208	11.93932613	2.815433644	4.626203154	5.0782579
908		Chromium Comp.									
909		0.000845	lb/1000 gal - NCASI	0.4	ppm in fuel oil - NCASI						
910		10191.342	1000 gal oil/yr	81.530736	MM lb/yr Oil						
911	0.002101819	0.004305842	Ton/yr	0.016306147	Ton /yr		8.61168399	4.203637743	0.991267262	1.628809027	1.78797
912		Cobalt Comp.		All power & recovery oil usage basis							
913		0.15	ppm in fuel oil - NCASI								
914		81.530736	MM lb/yr Oil								
915	0.002984832	0.006114805	Ton /yr				12.2296104	5.969663067	1.407716822	2.313101577	2.5391289
916		Copper Comp.		All power & recovery oil usage basis							
917		0.00176	lb/1000 gal - NCASI	5.3	ppm in fuel oil - NCASI						
918		10191.342	1000 gal oil/yr	81.530736	MM lb/yr Oil						
919	0.004377753	0.008968381	Ton/yr	0.21605645	Ton /yr		17.93676192	8.755505832	2.064651339	3.39254898	3.7240558
920		Hydrogen Fluoride		All power & recovery oil usage basis							
921		0.00023	lb/MMBTU from Oil	NCASI factor							
922		1599293.329	MMBTU/yr from Oil								
923	0.089776602	0.183918733	Ton Mn/yr				367.8374657	179.5532042	42.34075912	69.5725697	76.370933
924		Lead Compounds		All power & recovery oil usage basis							
925		0.00151	lb/1000 gal - NCASI	1.37	ppm in fuel oil - NCASI	0.00001					
926		10191.342	1000 gal oil/yr	81.530736	MM lb/yr Oil	lb/MMBTU oil					
927	0.003755913	0.007694463	Ton/yr	0.055848554	Ton /yr	15.99293329	15.38892642	7.511826026	1.771377001	2.910652818	3.1950706
928		Manganese Comp.		All power & recovery oil usage basis							
929		0.003	lb/1000 gal - NCASI	0.49	ppm in fuel oil - NCASI	0.00002					
930		10191.342	1000 gal oil/yr	81.530736	MM lb/yr Oil	lb/MMBTU oil					
931	0.007462079	0.015287013	Ton/yr	0.01997503	Ton /yr	31.98586658	30.574026	14.92415767	3.519292054	5.782753943	6.3478223
932		Mercury Comp.		All power & recovery oil usage basis							

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Row #												
933		0.00000021	lb/MMBTU from Oil	0.006	ppm in fuel oil - NCASI							
934		1599293.329	MMBTU/yr from Oil	81.530736	MM lb/yr Oil							
935	8.19699E-05	0.000167926	Ton Mn/yr	0.000244592	Ton /yr		0.335851599	0.163939882	0.038658954	0.063522781	0.06973	
936		Naphthalene		All power & recovery oil usage basis								
937		0.00113	lb/1000 gal - NCASI									
938		10191.342	1000 gal oil/yr									
939	0.002810716	0.005758108	Ton/yr				11.51621646	5.621432721	1.325600007	2.178170652	2.3910131	
940		Nickel Comp.		All power & recovery oil usage basis								
941		0.0845	lb/1000 gal - NCASI	24	ppm in fuel oil - NCASI							
942		10191.342	1000 gal oil/yr	81.530736	MM lb/yr Oil							
943	0.210181887	0.4305842	Ton/yr	0.978368832	Ton /yr		861.168399	420.3637743	99.1267262	162.8809027	178.797	
944		Selenium Comp.										
945		0.09	ppm in fuel oil - NCASI									
946		81.530736	MM lb/yr Oil									
947	0.001790899	0.003668883	Ton /yr	All power & recovery oil usage basis			7.33776624	3.58179784	0.844630093	1.387860946	1.5234774	
948		Silver										
949		0.0002	ppm in fuel oil - NCASI									
950		81.530736	MM lb/yr Oil									
951	3.97978E-06	8.15307E-06	Ton /yr	All power & recovery oil usage basis			0.016306147	0.007959551	0.001876956	0.003084135	0.0033855	
952		Zinc Comp.										
953		0.00132	lb/1000 gal - NCASI	0.77	ppm in fuel oil - NCASI							
954		10191.342	1000 gal oil/yr	81.530736	MM lb/yr Oil							
955	0.003283315	0.006726286	Ton/yr	0.031389333	Ton /yr		13.45257144	6.566629374	1.548488504	2.544411735	2.7930418	
956		PCBs										
957		0.05	ppm in fuel oil - NCASI									
958		81.530736	MM lb/yr Oil									
959	0.000994944	0.002038268	Ton /yr	All power & recovery oil usage basis			4.0765368	1.989887689	0.469238941	0.771033859	0.8463763	
960		Formaldehyde										
961		0.0141	lb CHOH/hr	Stack test 1991 by ESE for A scrubber								
962		8084.39	hr/yr									
963	0.026507621	0.113989899	Ton /yr	Double for both PB scrubbers			227.979798	111.2842139	26.2421276	43.11996974	47.333487	
964		Chloroform										
965		0.0675	lb CHCl3/hr	Stack test 1991 by ESE for A scrubber								
966		8084.39	hr/yr									
967	0.126898187	0.545696325	Ton /yr	Double for both PB scrubbers			1091.39265	532.7435774	125.6272066	206.425387	226.59648	
968		Total HAPS										
969		2.51652726	Ton total HAPS/yr	For all PBs & recovery oil		5033.054521	5033.054521	2749.536513	648.3730753	1065.379599	569.76533	
970		5033.054521	lb total HAPS/day				25000	10000	lb/yr			
971	Total HAPS						total	individual	thresholds			
972	Below Threshold	1.206160169	Ton Total HAPS/yr from No. 1 PB on oil		2412.320338	lb/yr						
973		7.161417017	lb/day Total HAPS		Method Code	4						
974												
975	Methanol											
976	Below Threshold	0.704989928	Ton MeOH/yr from No. 1 PB on oil		0.584491136	Methanol % of Total						
977		4.185784769	lb/day MeOH		Method Code	4						
978												
979												

Row #							
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980	EU ID 002	No. 2 Power Boiler - Oil Fired					
981	CO						
982	lbs (CO)/1000 gal (Fuel Oil)		5	Emission Factor from AP-42, Table 1.3-1[9/98].			
983	Tons (CO)/yr		2.932743379				
984	lbs (CO)/day		17.30897975		Method Code	3	
985	Example Calculation:						
986	Tons (CO)/yr	= [Fuel Oil Usage (1000 gal/yr)] x [lbs (CO)/1000 gal (Fuel Oil)] / [2000 lbs/ton]					
987	lbs (CO)/day	= [Ozone Rate (1000 gal/day)] x [lbs (CO)/1000 gal (Fuel Oil)]					
988							
989	NOx						
990	lbs (NOx)/1000 gal (Fuel Oil)		47	Emission Factor from AP-42, Table 1.3-1[9/98].			
991	Tons (NOx)/yr		27.56778776				
992	lbs (NOx)/day		162.7044097		Method Code	3	
993	Example Calculation:						
994	Tons (NOx)/yr	= [Fuel Oil Usage (1000 gal/yr)] x [lbs (NOx)/1000 gal (Fuel Oil)] / [2000 lbs/ton]					
995	lbs (NOx)/day	= [Ozone Rate (1000 gal/day)] * [lbs (NOx)/1000 gal (Fuel Oil)]					
996							
997	Lead						
998	lbs (Pb)/hr [A scrubber - No. 1 & 2 PBs]		0.07	Average from 06-14-95 Stack Test Data.			
999	Tons (Pb)/yr [A scrubber - No. 1 & 2 PBs]		0.28465045				
1000	Tons (Pb)/yr [No. 2 PB using ratio of Oil Usage]		0.054315656		Method Code	2	
1001	lbs (Pb)/day		0.320569673				
1002	Example Calculation:						
1003	Tons (Pb)/yr [A scrubber - No. 1 & 2 PBs]		= [lbs (Pb)/hr from A scrubber] x [Hours of Oper (hrs/yr)] / [2000 lbs/ton]				
1004	Tons (Pb)/yr [No. 2 PB using ratio of Oil Usage]		= [Tons (Pb)/yr A scrubber] x [Oil Usage(1000 gal/yr)No2PB] / [Oil Usage (1000 gal/yr)No 1&2 PB]				
1005	lbs (Pb)/day		= [Tons (Pb)/yr (No.2 PB using ratio of Oil)] x [2000 lbs/ton] / [Days of Operation (days/yr)]				
1006							
1007	SO2						
1008	A scrubber efficiency for SO2 (%)		0.9		A Scrubber Average pH=	6	
1009	Density of Oil (lbs/gal)		8				
1010	Tons (SO2)/yr		14.04979595				
1011	lbs (SO2)/day		82.92155234		Method Code	2	
1012							
1013	Example Calculation:						
1014	Tons (SO2)/yr	= [Oil Usage(1000 gal/yr)] x Density of Oil(lb/gal) x [%S/100] x [MW(SO2)/MW(S)] x [1 - A scrub. eff SO2(%)] / [2000 lbs/ton]					
1015	lbs (SO2)/day	= [Ozone Rate (1000 gal/day)] x Density of Oil (lbs/gal) x [%S / 100] x [MW (SO2) /MW (S)] x [1 - A scrubber eff SO2 (%)]					
1016							
1017	VOC						
1018	lbs (VOC)/1000 gal (Fuel Oil)		0.76	Emission Factor from AP-42, Table 1.3-3 [9/98].			
1019	Tons (VOC)/yr		0.445776994				
1020	lbs (VOC)/day		2.630964923		Method Code	3	
1021	Example Calculation:						
1022	Tons (VOC)/yr	= [Oil Usage (1000 gal/yr)] x [lbs (VOC)/1000 gal (Fuel Oil)] / [2000 lbs/ton]					
1023	lbs (VOC)/day	= [Ozone Rate (1000 gal/day)] x [lbs (VOC)/1000 gal (Fuel Oil)]					
1024							
1025	PM						
1026	lbs (PM)/1000 gal (Fuel Oil)		16.97819583	Emission Factor from AP-42, Table 1.3-1 [9/98].		[(9.19) S + 3.22)]	
1027	Sulfur Content (% by weight)		1.497083333		Table 1.3-5 [9/98]	8.34[1.12S + .37] = 9.34S + 3.09	
1028	A scrubber efficiency for PM (%)		0.8				
1029	Tons (PM)/yr		1.991707656				
1030	lbs (PM)/day		11.75500992		Method Code	3	
1031	Example Calculation:						
1032	Tons (PM)/yr	= [Oil Usage (1000 gal/yr)] x [lbs (PM)/1000 gal (Oil)] x [1 - A scrubber eff PM] / [2000 lbs/ton]					
1033	lbs (PM)/day	= [Ozone Rate (1000 gal/day)] x [lbs (PM)/1000 gal (Oil)] x [1 - A scrubber eff PM]					
1034							
1035	PM10						
1036	lbs (PM10)/1000 gal (Fuel Oil)		14.675078	Emission Factor from AP-42, Table 1.3-5.		[7.17 x (1.12 S + .37)]	
1037	Sulfur Content (% by weight)		1.497083333				
1038	Tons (PM10)/yr		1.721529513				
1039	lbs (PM10)/day		10.16042512		Method Code	3	
1040	Example Calculation:						
1041	Tons (PM10)/yr	= [Oil Usage (1000 gal/yr)] x [lbs (PM10)/1000 gal (Oil)] x [1 - A scrubber eff PM] / [2000 lbs/ton]					
1042	lbs (PM10)/day	= [Ozone Rate (1000 gal/day)] x [lbs (PM10)/1000 gal (Oil)] x [1 - A scrubber eff PM]					
1043							
1044	Total HAPS						
1045	Below Threshold	0.324186538	Ton Total HAPS/yr from No. 2 PB on oil		Method Code	4	
1046		1.913341023	lb/day Total HAPS				
1047							
1048	Methanol		0.166244924	Ton MeOH/yr from No. 1 PB on oil		Method Code	4
1049	Below Threshold		0.981173476	lb/day MeOH	No. 2 PB Oil MeOH/VOC ratio =	0.372932937	
1050							

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Row #										
1051	EU ID 002	No. 2 Power Boiler - Bark Fired								
1052										
1053	CO									
1054	lbs (CO)/MMBTU Input(Bark-wet)		0.6	Emission Factor from AP-42, Table 1.6-2 [7/01]. = 0.6 lb/MMBTU heat input				minus oil from 1 & 2 PB		
1055	Tons (CO)/yr		275.8359038	Steam meter bark usage basis		2004 Test T/yr A Scrub	377.693952	362.3244106	Ton CO/yr	
1056	lbs (CO)/day		1627.976764					2138.429817	lb CO/day	
1057	Example Calculation:				Method Code	3				
1058	Tons (CO)/yr	= [Bark Usage (MMBTU/yr)] x [lbs (CO)/MMBTU (Bark)] / [2000 lbs/ton]								
1059	lbs (CO)/day	= [CO (tons/yr)] x [2000 lb/ton] / [Hours of Oper. (days/yr)]								
1060										
1061	NOx									
1062	lbs (NOx)/MMBTU Input (Bark)		0.22	Emission Factor from AP-42, Table 1.6-2 [7/01]. = .22 lb/MMBTU Heat Input			total NOX Oil & bark #2PB			
1063	Tons (NOx)/yr		101.1398314				128.7076191	ton/yr		
1064	lbs (NOx)/day		596.9248133		Method Code	3				
1065	Example Calculation:							minus oil from 1 & 2 PB		
1066	Tons (NOx)/yr	= [Bark Usage (MMBTU/yr)] x [lbs (NOx)/MMBTU (Bark)] / [2000 lbs/ton]				2004 Test T/yr A Scrub	223.926492	79.45280253	Ton NOX/yr	
1067	lbs (NOx)/day	= [NOX (tons/yr)] x [2000 lbs /ton] / [Hours of Oper. (days/yr)]						468.928499	lb NOX/day	
1068										
1069	Lead									
1070	lbs (Pb)/MMBTU Input (Bark)		0.000048	Emission Factor from AP-42, Table 1.6-2 [7/01]. = .000048 lb/MMBTU Heat Input						
1071	Tons (Pb)/yr		0.022066872		Method Code	3				
1072	lbs (Pb)/day		0.130238141							
1073	Example Calculation:									
1074	Tons (Pb)/yr	= [Bark Usage (MMBTU/yr)] x [lbs (Pb)/MMBTU (Bark)] / [2000 lbs/ton]								
1075	lbs (Pb)/day	= [Pb (tons/yr)] x [2000 lbs /ton] / [Hours of Oper. (days/yr)]								
1076										
1077	SO2									
1078	lbs (SO2)/MMBTU(Bark)		0.025	Emission Factor from AP-42, Table 1.6-2 [7/01].= .025 lb/MMBTU			total SO2 Oil & bark #2PB			
1079	A scrubber efficiency for SO2 (%)		0.9				15.19911221	ton/yr		
1080	Tons (SO2)/yr		1.149316266							
1081	lbs (SO2)/day		6.783236515		Method Code	3				
1082	Example Calculation:									
1083	Tons (SO2)/yr	= [Bark Usage (MMBTU/yr)] x [lbs (SO2)/MMBTU (Bark)] x [1-Eff.] / [2000 lbs/ton]								
1084	lbs (SO2)/day	= [SO2(tons/yr)] x [lbs (SO2)/ton (Bark)] / [Hours of Oper. (days/yr)]								
1085										
1086	VOC									
1087	lbs (VOC)/MMBTU (Bark)		0.038	Emission Factor from AP-42, Table 1.6-3 [7/01].= .038 lb/MMBTU						
1088	Tons (VOC)/yr		17.46960724							
1089	lbs (VOC)/day		103.105195		Method Code	3				
1090	Example Calculation:									
1091	Tons (VOC)/yr	= [Bark Usage (MMBTU/yr)] x [lbs (VOC)/MMBTU (Bark)] / [2000 lbs/ton]								
1092	lbs (VOC)/day	= [VOC (tons/yr)] x [2000 lbs/ton] / [Hours of Oper. (days/yr)]								
1093										
1094	PM									
1095	Tons (PM)/yr	No. 2 PB total	72.62614414	A Scrubber x ratio from single boiler testing in 1999.			128.1792669	#1PB+#2PB steam rate avg.		
1096	Tons (PM)/yr [A Scrubber Total #1&#2PB]		113.5779183	72.62614414	No. 2 PB T PM/yr total [oil & bark]		196.6872667	#1PB+#2PB steam rate tests		
1097	Tons (PM)/yr [No. 1 PB - Oil by emis. factor]		8.446175718	40.95177418	No. 1 PB T PM/yr by ratio from 1999 single boiler tests		0.651690722	A Scrubber production ratio: avg/test		
1098	Tons (PM)/yr [No. 2 PB - Oil - by emis. factor]		1.991707656	1.991707656	No. 2 PB T PM/yr oil by emis. factor.		total PM Oil & bark #2PB			
1099	Tons (PM)/yr [No. 2 PB - Bark]		103.140035	70.63443649	No. 2 PB lb/yr bark by difference.		105.1317426	ton/yr		
1100	lbs (PM)/day		608.7299659	416.8827181	Method Code	1				
1101	Example Calculation:									
1102	Tons (PM)/yr [A Scrubber]	= [Annual Avg. PM Rate from Tests (lbs/hr)] x [Hours of Oper (hrs/yr)] x [Prod. Ratio] / [2000 lbs/ton]								
1103	Tons (PM)/yr	= [Tons (PM)/yr from A Scrubber] - [Tons (PM)/yr from No. 1 PB (Oil fired)] - [Tons (PM)/yr from No. 2 PB (Oil Fired)]								
1104	lbs (PM)/day	= [Tons (PM)/yr from No. 2 PB (Bark fired)] x [2000 lbs/ton] / [Days of Oper (days/yr)]								
1105										
1106	PM10									
1107	lbs (PM10)/MMBTU (Bark-wet)		0.5	Emission Factor from AP-42, Table 1.6-1 [7/01].= .5 lb/MMBTU Input						
1108	Tons (PM10)/yr		229.8632531	63.06646115	Using test PM & ratio of AP-42 factors [.5/.56]		0.892857143			
1109	lbs (PM10)/day		1356.647303	372.2167126						
1110	Example Calculation:				Method Code	2				
1111	Tons (NOx)/yr	= [Bark Usage (MMBTU/yr)] x [lbs (PM10)/MMBTU (Bark)] / [2000 lbs/ton]								
1112	lbs (NOx)/day	= [Tons (PM10)/yr] x [2000] / [Hours of Oper. (days/yr)]								
1113										
1114	Total HAPS									
1115		Methanol								
1116		0.030173397	lb MeOH/ODUT	from all power boilers	G:RWH/MACT methanol/Methanol Data Review Sortll 9904.xls.			Bark	Bark	Bark
1117		200948.2887	ODUBT/yr				All Bark Lb/yr	No. 2 PB lb/yr	No. 3 PB lb/yr	No. 3 PB lb/yr
1118		3.03164625	T MeOH/yr	Total from all power boilers and all SCC			3774.489346	1660.646232	2113.843114	2329.164607
1119		1.887244673	T MeOH/yr	Total from bark						
1120										
1121		Acetaldehyde								
1122		0.00011	lb/MMBTU from Bark							
1123		2366986.195	MMBTU/yr from Bark							

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Row #												
1124		0.130184241	Ton /yr				260.3684814	114.5532277	145.8152537	145.3613123		
1125		Benzene										
1126		0.000062	lb/MMBTU from Bark	NCASI factor								
1127		2366986.195	MMBTU/yr from Bark									
1128		0.073376572	Ton /yr				146.7531441	64.5663647	82.18677937	81.93092147		
1129		Acrolein										
1130		0.000012	lb/MMBTU from Bark									
1131		2366986.195	MMBTU/yr from Bark									
1132		0.014201917	Ton /yr				28.40383434	12.49671575	15.90711859	15.8575977		
1133		Arsenic		No. 3 PB Bark 12/18/02	0.00028	lb As/hr						
1134		0.0000089	lb/MMBTU from Bark		2.2772036	lb/yr						
1135		2366986.195	MMBTU/yr from Bark									
1136		0.010533089	Ton /yr				21.06617713	9.268397513	11.79777962	2.2772036		
1137		Cumene										
1138		0.0000063	lb/MMBTU from Bark									
1139		2366986.195	MMBTU/yr from Bark									
1140		0.007456007	Ton /yr				14.91201303	6.560775768	8.351237259	8.325238794		
1141		Barium Compounds		No. 3 PB Bark 12/18/02	0.00681	lb Ba/hr						
1142		0.00032	lb/MMBTU from Bark		55.3848447	lb Ba/yr						
1143		2366986.195	MMBTU/yr from Bark		94.19466288	lb BaSO4/yr						
1144		0.378717791	Ton /yr				757.4355823	333.2457533	424.189829	94.19466288		
1145		Carbon Tetrachloride										
1146		0.0000068	lb/MMBTU from Bark									
1147		2366986.195	MMBTU/yr from Bark									
1148		0.008047753	Ton /yr				16.09550612	7.081472258	9.014033867	8.985972032		
1149		Carbon Disulfide										
1150		0.00013	lb/MMBTU from Bark									
1151		2366986.195	MMBTU/yr from Bark									
1152		0.153854103	Ton /yr				307.7082053	135.3810873	172.327118	171.7906418		
1153		Chromium Comp.		No. 3 PB Bark 12/18/02	lb Cr/hr	0.00178						
1154		0.0000096	lb/MMBTU from Bark	1.87	ppm in wet bark-NCASI lbCr/yr	14.4765086						
1155		2366986.195	MMBTU/yr from Bark	473.3972389	MM lb/yr wet bark lb CrSO4/yr	41.20237063						
1156		0.011361534	Ton /yr	0.442626418	Ton /yr		22.72306747	9.997372599	12.72569487	41.20237063		
1157		Cobalt Comp.		No. 3 PB Bark 12/18/02	0.0061	lb Co/hr						
1158		0.62	ppm in wet bark - NCASI		49.610507	lb Co/yr						
1159		473.3972389	MM lb/yr wet bark		130.3326879	lb CoSO4/yr						
1160		0.146753144	Ton /yr				293.5062881	129.1327294	164.3735587	130.3326879		
1161		Copper Comp.		No. 3 PB Bark 12/18/02	lb Cu/hr	0.00927						
1162		0.000034	lb/MMBTU from Bark	3.64	ppm in wet bark-NCASI lbCu/yr	75.3917049						
1163		2366986.195	MMBTU/yr from Bark	473.3972389	MM lb/yr wet bark lb CuSO4/yr	189.3697155						
1164		0.040238765	Ton /yr	0.861582975	Ton /yr		80.47753062	35.40736129	45.07016933	189.3697155		
1165		Dichloromethane										
1166		0.00093	lb/MMBTU from Bark									
1167		2366986.195	MMBTU/yr from Bark									
1168		1.100648581	Ton /yr				2201.297161	968.4954705	1232.801691	1228.963822		
1169		n-Hexane										
1170		0.00055	lb/MMBTU from Bark									
1171		2366986.195	MMBTU/yr from Bark									
1172		0.650921204	Ton /yr				1301.842407	572.7661385	729.0762686	726.8065614		
1173		Methyl Isobutyl Ketone										
1174		0.00021	lb/MMBTU from Bark									
1175		2366986.195	MMBTU/yr from Bark									
1176		0.24853355	Ton /yr				497.0671009	218.6925256	278.3745753	277.5079598		
1177		Lead Compounds		No. 3 PB Bark 12/18/02	lb Pb/hr	0.005						
1178		0.0000028	lb/MMBTU from Bark	4.8	ppm in wet bark-NCASI lbPb/yr	40.66435						
1179		2366986.195	MMBTU/yr from Bark	473.3972389	MM lb/yr wet bark lb PbSO4/yr	59.52317899						
1180		0.003313781	Ton /yr	1.136153373	Ton /yr		6.627561345	2.915900341	3.711661004	59.52317899		
1181		Manganese Comp.		No. 3 PB Bark 12/18/02	lb Mn/hr	0.0146						
1182		0.00075	lb/MMBTU from Bark	60.6	ppm in wet bark-NCASI lbMn/yr	118.739902						
1183		2366986.195	MMBTU/yr from Bark	473.3972389	MM lb/yr wet bark lb MnSO4/yr	325.9950037						
1184		0.887619823	Ton /yr	14.34393634	Ton /yr		1775.239646	781.0447343	994.1949118	325.9950037		
1185		Mercury Comp.		No. 3 PB Bark 12/18/02	lb Hg/hr	0.00014						
1186		0.04	ppm in wet bark - NC	0.04	ppm in wet bark-NCASI lbHg/yr	1.1386018						
1187		493.1496814	MM lb/yr wet bark	473.3972389	MM lb/yr wet bark lb HgSO4/yr	1.683495981						
1168		0.009862994	Ton /yr	0.009467945	Ton /yr		19.72598726	8.6787598	11.04722746	1.683495981		
1169		Napthalene										
1190		0.00012	lb/MMBTU from Bark									
1191		2366986.195	MMBTU/yr from Bark									
1192		0.142019172	Ton /yr				284.0383434	124.9671575	159.0711859	158.575977		
1193		Nickel Comp.		No. 3 PB Bark 12/18/02	lb Ni/hr	0.00267						
1194		0.000016	lb/MMBTU from Bark	3.25	ppm in wet bark-NCASI lbNi/yr	21.7147629						
1195		2366986.195	MMBTU/yr from Bark	473.3972389	MM lb/yr wet bark lb NiSO4/yr	57.04725847						
1196		0.01893589	Ton /yr	0.769270513	Ton /yr		37.87177912	16.66228766	21.20949145	57.04725847		

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Row #												
1197		Phenol										
1198		0.0000021	lb/MMBTU from Bark									
1199		2366986.195	MMBTU/yr from Bark									
1200		0.002485336	Ton /yr				4.970671009	2.186925256	2.783745753	2.775079598		
1201		Selenium Comp.		No. 3 PB Bark 12/18/02	0.00086	lb Se/hr						
1202		0.21	ppm in wet bark - NCASI		6.9942682	lb Se/yr						
1203		473.3972389	MM lb/yr wet bark		15.49363209	lb SeSO4/yr						
1204		0.04970671	Ton /yr				99.41342018	43.73850512	55.67491506	15.49363209		
1205		Silver		No. 3 PB Bark 12/18/02	0.00024	lb Ag/hr						
1206		0.15	ppm in wet bark - NCASI		1.9518888	lb Ag/yr						
1207		473.3972389	MM lb/yr wet bark		3.686901067	lb AgSO4/yr						
1208		0.035504793	Ton /yr				71.00958584	31.24178937	39.76779647	3.686901067		
1209		Toluene										
1210		0.00001	lb/MMBTU from Bark									
1211		2366986.195	MMBTU/yr from Bark									
1212		0.011834931	Ton /yr				23.66986195	10.41392979	13.25593216	13.21466475		
1213		1,1,1-Trichloroethane										
1214		0.0000012	lb/MMBTU from Bark									
1215		2366986.195	MMBTU/yr from Bark									
1216		0.001420192	Ton /yr				2.840383434	1.249671575	1.590711859	1.58575977		
1217		1,1,2-Trichloroethane										
1218		0.0000028	lb/MMBTU from Bark									
1219		2366986.195	MMBTU/yr from Bark									
1220		0.003313781	Ton /yr				6.627561345	2.915900341	3.711661004	3.700106131		
1221		Xylene										
1222		0.0000013	lb/MMBTU from Bark									
1223		2366986.195	MMBTU/yr from Bark									
1224		0.001538541	Ton /yr				3.077082053	1.353810873	1.72327118	1.717906418		
1225		Zinc Comp.		No. 3 PB Bark 12/18/02	lb Zn/hr	0.11065						
1226		0.00031	lb/MMBTU from Bark	10	ppm in wet bark-NCASI lbZn/yr	899.9020655						
1227		2366986.195	MMBTU/yr from Bark	473.3972389	MM lb/yr wet bark lb ZnSO4/yr	2228.988193						
1228		0.36688286	Ton /yr	2.366986195	Ton /yr		733.7657204	322.8318235	410.9338969	2228.988193		
1229		PCBs										
1230												
1231												
1232							0	0	0	0		
1233		Formaldehyde										
1234		0.0141	lb CHOH/hr	Stack test 1991 by ESE for A scrubber - double for both scrubbers								
1235		8132.87	hr/yr									
1236		0.114673467	Ton /yr				229.346934	100.9048077	128.4421263	136.674048		
1237		Chloroform										
1238		0.0675	lb CHCl3/hr	Stack test 1991 by ESE for A scrubber - double for both scrubbers								
1239		8132.87	hr/yr									
1240		0.548968725	Ton /yr				1097.93745	483.0549305	614.8825195	654.2906554		
1241		Total HAPS										
1242		7.060153916	Ton/yr	14120.30783		14120.30783	14120.30783	6212.452557	7907.855275	9117.023135		
1243							25000	10000	lb/yr	with 2002 tests		
1244	Total HAPS						total	individual				
1245	Below Threshold	3.106226279	Ton HAPS/yr from No. 2 PB on bark									
1246		18.33287159	lb/day total HAPS									
1247												
1248	Methanol											
1249	Below Threshold	0.830323116	Ton MeOH/yr from No. 2 PB on bark		No. 2 PB Bark MeOH/VOC =	0.047529581						
1250		4.900546739	lb/day MeOH									
1251												
1252	EU ID 003	No. 3 Power Boiler - Oil Fired										
1253												
1254	CO											
1255	lbs (CO)/1000 gal (Fuel Oil)		5	Emission Factor from AP-42, Table 1.3-1[9/98].								
1256	Tons (CO)/yr		4.818961619									
1257	lbs (CO)/day		28.27510576		Method Code	3						
1258	Example Calculation:											
1259	Tons (CO)/yr	= [Fuel Oil Usage (1000 gal/yr)] x [lbs (CO)/1000 gal (Fuel Oil)] / [2000 lbs/ton]										
1260	lbs (CO)/day	= [Ozone Rate (1000 gal/day)] x [lbs (CO)/1000 gal (Fuel Oil)]										
1261												
1262	NOx											
1263	lbs (NOx)/1000 gal (Fuel Oil)		47	Emission Factor from AP-42, Table 1.3-1[9/98].								
1264	Tons (NOx)/yr		45.29823922									
1265	lbs (NOx)/day		265.7859942		Method Code	3						
1266	Example Calculation:											
1267	Tons (NOx)/yr	= [Fuel Oil Usage (1000 gal/yr)] x [lbs (NOx)/1000 gal (Fuel Oil)] / [2000 lbs/ton]										
1268	lbs (NOx)/day	= [Ozone Rate (1000 gal/day)] x [lbs (NOx)/1000 gal (Fuel Oil)]										
1269												

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Row #	A	B	C	D	E	F	G	H	I	J	K	L
1270	Lead											
1271	lbs (Pb)/hr [B scrubber - No. 3 PB]		0.07	Average from 06-14-95 Stack Test Data.								
1272	Tons (Pb)/yr [B scrubber - No. 3 PB]		0.2863245									
1273	lbs (Pb)/day		1.68		Method Code	2						
1274	Example Calculation:											
1275	Tons (Pb)/yr [B scrubber - No. 3 PB]		= [lbs (Pb)/hr from B scrubber] x [Hours of Oper (hrs/yr)] / [2000 lbs/ton]									
1276	lbs (Pb)/day		= [Tons (Pb)/yr] x [2000 lbs/ton] / [Days of Operation (days/yr)]									
1277												
1278	SO2											
1279	B scrubber efficiency for SO2 (%)		0.9		B Scrubber Average pH=	7.4	Env - 3K - Air Report - Power Boilers					
1280	Density of Oil (lbs/gal)		8									
1281	Tons (SO2)/yr		23.0860388									
1282	lbs (SO2)/day		135.4566067		Method Code	2						
1283												
1284	Example Calculation:											
1285	Tons (SO2)/yr	= [Oil Usage(1000 gal/yr)] x Density of Oil(lb/gal) x [%S/100] x [MW(SO2)/MW(S)] x [1 - B scrub. eff SO2(%)] / [2000 lbs/ton]										
1286	lbs (SO2)/day	= [Ozone Rate (1000 gal/day)] x Density of Oil (lbs/gal) x [%S / 100] x [MW (SO2) /MW (S)] x [1 - B scrubber eff SO2 (%)]										
1287												
1288	VOC											
1289	lbs (VOC)/1000 gal (Fuel Oil)		0.76	Emission Factor from AP-42, Table 1.3-3 [9/98].								
1290	Tons (VOC)/yr		0.732482166									
1291	lbs (VOC)/day		4.297816076		Method Code	3						
1292	Example Calculation:											
1293	Tons (VOC)/yr	= [Oil Usage (1000 gal/yr)] x [lbs (VOC)/1000 gal (Fuel Oil)] / [2000 lbs/ton]										
1294	lbs (VOC)/day	= [Ozone Rate (1000 gal/day)] x [lbs (VOC)/1000 gal (Fuel Oil)]										
1295												
1296	PM											
1297	lbs (PM)/1000 gal (Fuel Oil)		16.97819583	Emission Factor from AP-42, Table 1.3-1 [9/98].		[(9.19) S + 3.22)]						
1298	Sulfur Content (% by weight)		1.497083333		Table 1.3-5 [9/98]	8.34[1.12S + .37] = 9.34S + 3.09						
1299	B scrubber efficiency for PM (%)		0.8									
1300	Tons (PM)/yr		3.272690963									
1301	lbs (PM)/day		26.88337584		Method Code	3						
1302	Example Calculation:											
1303	Tons (PM)/yr	= [Oil Usage (1000 gal/yr)] x [lbs (PM)/1000 gal (Oil)] x [1 - B scrubber eff PM] / [2000 lbs/ton]										
1304	lbs (PM)/day	= [Ozone Rate (1000 gal/day)] x [lbs (PM)/1000 gal (Oil)] x [1 - B scrubber eff PM]										
1305												
1306	PM10											
1307	lbs (PM10)/1000 gal (Fuel Oil)		14.675078	Emission Factor from AP-42, Table 1.3-5.		[7.17 x (1.12 S + .37)]						
1308	Sulfur Content (% by weight)		1.497083333									
1309	Tons (PM10)/yr		2.828745506									
1310	lbs (PM10)/day		16.5975753		Method Code	3						
1311	Example Calculation:											
1312	Tons (PM10)/yr	= [Oil Usage (1000 gal/yr)] x [lbs (PM10)/1000 gal (Oil)] x [1 - B scrubber eff PM] / [2000 lbs/ton]										
1313	lbs (PM10)/day	= [Ozone Rate (1000 gal/day)] x [lbs (PM10)/1000 gal (Oil)] x [1 - B scrubber eff PM]										
1314												
1315	Total HAPS											
1318	Below Threshold	0.5326898	Ton Total HAPS/yr from No. 3 PB on oil									
1317		3.125540648	lb/day Total HAPS									
1318												
1319												
1320	Methanol		0.273166726	Ton MeOH/yr from No. 3 PB on oil								
1321	Below Threshold		1.602797173	lb/day MeOH								
1322												
1323					No. 3 PB Oil MeOH/VOC =	0.372932937						
1324												
1325												
1326	**EU ID 003**	**No. 3 Power Boiler - Bark Fired**										
1327												
1328	CO											
1329	lbs (CO)/MMBTU Input(Bark-wet)		0.6	Emission Factor from AP-42, Table 1.6-2 [7/01]. = 0.6 lb/MMBTU heat input			133.2333333	ppmV CO 2004	385	dscf/mole		
1330	Tons (CO)/yr		351.1126059	Steam meter bark burned basis			92886.8	dscf/m flue gas	28	lb CO/mole CO		
1331	lbs (CO)/day		2060.142174		Method Code	3	12.37561799	dscf/min CO	54.00269667	lb CO/hr	minus No. 3 PB oil CO	
1332	Example Calculation:								220.8899303	T CO/yr	216.07097	
1333	Tons (CO)/yr	= [Bark Usage (MMBTU/yr)] x [lbs (CO)/MMBTU (Bark)] / [2000 lbs/ton]							1296.06472	lb CO/day	1267.7896	
1334	lbs (CO)/day	= [CO (tons/yr)] x [2000 lb/ton] / [Hours of Oper. (days/yr)]										
1335												
1338	NOx											
1337	lbs (NOx)/MMBTU Input (Bark)		0.22	Emission Factor from AP-42, Table 1.6-2 [7/01]. = .22 lb/MMBTU Heat Input			total NOX Oil & bark #2PB					
1338	Tons (NOx)/yr		128.7412888				174.0395281	ton/yr				
1339	lbs (NOx)/day		755.3854639		Method Code	3	B Scrubber					
1340	Example Calculation:						59.86666667	ppmV NOX 2004	385	dscf/mole		
1341	Tons (NOx)/yr	= [Bark Usage (MMBTU/yr)] x [lbs (NOx)/MMBTU (Bark)] / [2000 lbs/ton]					92886.8	dscf/m flue gas	46	lb NO2/mole NO2		
1342	lbs (NOx)/day	= [NOX (tons/yr)] x [2000 lbs /ton] / [Hours of Oper. (days/yr)]					5.560823093	dscf/min NOX	39.86460192	lb NOX/hr	minus No. 3 PB oil NOX	

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Row #												
1343									163.0601744	T NOX/yr	117.76194	
1344	Lead								956.750446	lb NOX/day	690.96445	
1345	lbs (Pb)/MMBTU Input (Bar	2002 Stack Test lb/yr	40.66435	0.000048	Emission Factor from AP-42, Table 1.6-2 [7/01]. = .000048 lb/MMBTU Heat Input							
1346	Tons (Pb)/yr		0.020332175	0.028089008	Method Code	2			Total NOX PB	T NOX/yr	386.98667	
1347	lbs (Pb)/day		0.119298397	0.164811374								
1348	Example Calculation:											
1349	Tons (Pb)/yr	= [Bark Usage (MMBTU/yr)] x [lbs (Pb)/MMBTU (Bark)] / [2000 lbs/ton]										
1350	lbs (Pb)/day	= [Pb (tons/yr)] x [2000 lbs /ton] / [Hours of Oper. (days/yr)]										
1351												
1352	SO2											
1353	lbs (SO2)/MMBTU(Bark)		0.025	Emission Factor from AP-42, Table 1.6-2 [7/01].= .025 lb/MMBTU			total SO2 Oil & bark #2PB					
1354	A scrubber efficiency for SO2 (%)		0.9				24.54900799	ton/yr				
1355	Tons (SO2)/yr		1.462969191									
1356	lbs (SO2)/day		8.583925726		Method Code	3						
1357	Example Calculation:											
1358	Tons (SO2)/yr	= [Bark Usage (MMBTU/yr)] x [lbs (SO2)/MMBTU (Bark)] x [1-Eff.] / [2000 lbs/ton]										
1359	lbs (SO2)/day	= [SO2(tons/yr)] x [lbs (SO2)/ton (Bark)] / [Hours of Oper. (days/yr)]										
1360												
1361	VOC											
1362	lbs (VOC)/MMBTU (Bark)		0.038	Emission Factor from AP-42, Table 1.6-3 [7/01].= .038 lb/MMBTU								
1363	Tons (VOC)/yr		22.23713171									
1364	lbs (VOC)/day		130.475671		Method Code	3						
1365	Example Calculation:											
1366	Tons (VOC)/yr	= [Bark Usage (MMBTU/yr)] x [lbs (VOC)/MMBTU (Bark)] / [2000 lbs/ton]										
1367	lbs (VOC)/day	= [VOC (tons/yr)] x [2000 lbs/ton] / [Hours of Oper. (days/yr)]										
1368												
1369	PM											
1370	lbs (PM)/hr [No. 3 PB = B Scrubber]		34.32666667	Average from Stack Test Data.		120.8323333	stack test steam rate					
1371	Tons (PM)/yr [No. 3 PB = B Scrubber]		106.7160033	ton/yr total PM Oil & bark #2PB		91.83761781	annual average steam rate					
1372	Tons (PM)/yr [No. 3 PB - Oil]		3.272690963			0.760041748	production ratio average/test					
1373	Tons (PM)/yr [No. 3 PB - Bark]		103.4433123									
1374	lbs (PM)/day		606.9503821		Method Code	1						
1375	Example Calculation:											
1376	Tons (PM)/yr [B Scrubber]		= [Annual Avg. PM Rate from Tests (lbs/hr)] x [Hours of Oper (hrs/yr)] x [production ratio] / [2000 lbs/ton]									
1377	Tons (PM)/yr [No. 3 PB (Bark fired)]		= [Tons (PM)/yr from B Scrubber] - [Tons (PM)/yr from No. 3 PB (Oil Fired)]									
1378	lbs (PM)/day		= [Tons (PM)/yr from No. 3 PB (Bark fired)] x [2000 lbs/ton] / [Days of Oper (days/yr)]									
1379												
1380	PM10											
1381	lbs (PM10)/MMBTU (Bark-wet)		0.5	Emission Factor from AP-42, Table 1.6-1 [7/01].= .5 lb/MMBTU Input								
1382	Tons (PM10)/yr		292.5938383	92.36010028	Using test PM & ratio of AP-42 factors [.5/.56]		0.892857143					
1383	lbs (PM10)/day		1716.785145	541.919984								
1384	Example Calculation:				Method Code	2						
1385	Tons (NOx)/yr	= [Bark Usage (MMBTU/yr)] x [lbs (PM10)/MMBTU (Bark)] / [2000 lbs/ton]										
1386	lbs (NOx)/day	= [Tons (PM10)/yr] x [2000] / [Hours of Oper. (days/yr)]										
1387												
1388												
1389	Total HAPS											
1390	Below Threshold	4.558511567	Ton HAPS/yr from No. 3 PB on bark									
1391		26.74692328	lb/day total HAPS									
1392												
1393												
1394	Methanol											
1395	Below Threshold	1.056921557	Ton MeOH/yr from No. 3 PB on bark		No. 3 PB Bark MeOH/VOC =	0.047529581						
1396		6.201454001	lb/day MeOH									
1397												
1398												
1399												

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Row #									
1400	*2004 Production vs Power Boiler Emissions Calculations*								
1401	**Total Power Boilers**								
1402	Average Electrical:	5.2	megawatt/day						
1403		27	klb steam/hr-megawatt						
1404		140	klb steam/hr						
1405	Average Total Steam Prod.	220	klb steam/hr						
1406	Average PB to Mill	80	klb steam/hr						
1407	Average % PB Steam to mill	36%							
1408			2004	1996	2003	2004	Present PSD Limit	Proposed PSD Limit	**Proposed PSD Limit**
1409		ADMT/yr:	145,883	149,957	144,976	145,883	153,205	175,000	**Change to 1996**
1410	**Table 7 Data**	2004 TPY	lb/ADMT	TPY	TPY	TPY	TPY	TPY	**TPY**
1411	PM	220.29	1.09	82	79	80	84	96	**14**
1412	PM10	195.37	0.97	73	70	71	74	85	**12**
1413	SO2	99.33	0.49	37	36	36	38	43	**6**
1414	NOx	298.8	1.48	111	107	108	114	130	**19**
1415	CO	647.14	3.21	241	233	234	246	281	**40**
1416	VOC	42.78	0.21	16	15	15	16	19	**3**

Rayonier

Performance Fibers

Fernandina Mill

October 20, 2005

RECEIVED
OCT 25 2005
BUREAU OF AIR REGULATION

Certified Mail, Return Receipt Requested

Mr. Jeffery F. Koerner, P. E.
Bureau of Air Regulation
Division of Air Resources Management
2600 Blair Stone Road, MS 5505
Tallahassee, FL 32399-2400

RE: October 12, 2005 completed letter Response regarding
Request to Install No. 6 Power Boiler, and the No.6 Batch Digester system
0890004-018-AC

Dear Mr. Koerner:

I am responding to your letter of October 12, 2005 requesting further information regarding Rayonier's application for No. 6 power boiler and to increase the production cap taken at the installation of No. 6 digester. Our responses follow in the same order as presented in your letter. The questions have not been repeated.

1. Please refer to page A.37 of the New Source Review Manual of 1990. This page gives guidance on evaluating separate, multiple, and minor projects to determine if they should be considered a single project. EPA guidance recommends asking two questions: First, Are the projects proposed at the same time? And second, Could the changes be considered as part of a single project?

A. Are the projects proposed at the same time?
The actual physical projects were proposed at greatly different times. The No. 6 digester was installed in 1998 and the No. 6 boiler is of course currently proposed. All the present permit amendment requests is a production increase which requires a new review of the emissions increases that could be expected from the installation of No. 6 digester. As stated in the application these two projects have been combined in this application for ease of permitting and were not proposed at the same time for any other reason. The events driving the two projects are different and occurred at different times.

The boiler project started because the maintenance costs have risen over the years and the facility was facing another major capital outlay for rebuilding boilers. Several boilers became available due to recent closures and boiler replacement was reconsidered. As an alternative we could simply overhaul the existing boilers and continue to use them, maintaining their reliability to produce sufficient steam for the proposed production.

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The digester installation began as a means to meet then existing commercial demand while taking digesters out of service for extended periods of maintenance. Since that time, a major competitor has left the dissolving pulp market and the facility now seeks to obtain a portion of the abandoned market before foreign competitors position themselves to meet that market demand. These events have occurred over the past several years. Realizing the full production increase made possible by the 1998 digester installation will take several years, as Rayonier will have to build market and upgrade certain process segments.

Because an application already was being prepared for the boiler, it was decided to add the separate production increase project at this time. The projects are presented in one application to spare both the DEP and Rayonier processing two permits instead of one.

B. Could the changes be considered as part of a single project?
These projects are not related. The permit application demonstrates this fact by showing that the boiler could be replaced without the production increase, and more importantly, the production increase could take place without the new boiler. The existing power boilers have sufficient steaming capacity to achieve the proposed production level and the recovery boiler has routinely operated at the higher operating rate.

In considering an issue such as this, EPA refers to its analysis as the "Circumvention Test." All of the guidance documents emphasize the importance of evaluating a source's intent in undertaking two projects. It is clear in making this analysis that the evidence of intent to circumvent NSR must be clear and convincing.

In the extreme case where the source has made a deliberate effort to circumvent PSD review (by the systematic construction of carefully sized emissions units which only in the aggregate would trigger review) a permitting agency may, however, make a finding that PSD applies to the total plant. Such a finding would have to be based on clear evidence that the source made a conscious effort to escape review by knowingly misrepresenting the intended source size through the calculated juggling of actual and scheduled construction of emission units.

U.S. EPA Region 10 PSD Applicability Determination, dated October 12, 2001, citing EPA Guidance Document dated October 21, 1986, entitled *Applicability of PSD to Portions of a Plant Construction in Phases Without Permits.*

No evidence in the present case would support a finding that Rayonier is attempting to circumvent NSR by disassociating two related projects. To the contrary, one project is driven by maintenance costs and concerns while the other is based upon a change in market dynamics.

2. None of the three air construction permits referenced in your letter could be considered contemporaneous emissions increases.

Project No. 08900004-014-AC: Brinks bypass AC - This Air construction permit allowed temporary and partial opening of the Brinks by-pass value to elevate stack particulates during testing to calibrate a new beta attenuation type particulate monitor.
The project lasted only a couple of days during the test.

Project no. 08900004-015-AC: Heat Input AC-Power boilers - This Air Construction Permit increased the permitted heat input to the existing three power boilers, but decreased the emission rate so that there was no increase in allowed (potential) emissions. No physical or operational change was made. No actual or potential emission changes resulted.

Project No. 08900004-017-AC: Subpart MM/Used Oil – This Air Construction Permit imposed the new 40 CFR Part 63, Subpart MM provisions which applied only to the recovery boiler. These provisions do not in any way apply to the power boilers. The Used Oil portion of the permit included reference to the fact that on-site generated on spec used oil is burned in the power boilers. After testing to demonstrate the Used Oil is on-spec, the used oil is loaded into the day tank along with the #6 oil being fed to the boilers. There are no emission factors for used oil. Used oil happens to be lower in ash and thus should form less particulate than the basic fuel - #6 oil. However, only 6,160 gallons of used oil was burned in 2004 vs 20,382,726 gallons of #6 oil. Any difference in emissions one way or the other is insignificant. (See also the projected emissions from burning Used Oil presented in answer to question 4.)

3. This application is not a PSD application. Thus no fee is provided.

4. Tire Derived Fuel (TDF) is delivered by truck which will be emptied into a bin as shown on Attachment 6 to the application. TDF will be metered onto the fuel conveyor feeding the boiler as shown on Attachment 6. TDF most likely used will be to augment Btu input when the waste wood fuel is wet. However, the boiler will be designed to produce twenty percent of its maximum Btus on TDF. The boiler is being permitted at 525 mmBtu/hr maximum, but at 450 mmBtu/hr annual average. Twenty percent of the maximum hourly operating rate is used to estimate maximum hourly fuel inputs and twenty percent of the annual average operating rate is used to estimate annual fuel input. TDF has a heat content of 15,500 Btu/lb. The metal emissions are estimated based on literature studies, specifically NCASI Technical Bulletin 906 "Alternative Fuels Used in the Forest Products Industry – Their Composition and Impact on Emissions" for the fuel analysis and the emission controls from the ESP and scrubber were conservatively estimated at 99.5%. The table below presents these results. These emissions are quite

small and do not trigger any sort of MACT review for hazardous Air Pollutants, which required 10 ton per year of any single pollutant or 25 tons per year of all combined.

Tire Derived Fuel Inputs and Emissions

TDF Hourly Rates		**ppm**							
Operating Rate mmBtu/hr	TDF Feed	Arsenic	Beryllium	Cadmium	Lead	Manganese	Mercury	Nickel	Selenium
ppm metal in fuel		3.82	0.03	1.1	70.65	470	0.011	30.95	0.71
		lbs/hr							
525 mmBtu/hr	3.39 ton/hr	0.0001293	1.016E-06	3.73E-05	0.002393	0.0159	3.73E-07	0.0010	2.41E-05
TDF Annual Rates		**Tons/year**							
450 mmBtu/hr	25432 tons/yr	0.00049	3.81 E-06	0.00014	0.00898	0.0598	1.399 E-06	0.003936	9.03E-05

Used Oil

Used Oil is a regulatory term for On-Specification Used Oil as defined by 40 CFR Part 279. This Part allows those who generate Waste Oil to follow specific procedures to handle it as Used Oil and to burn only that oil generated on-site provided it meets the analytical specifications. Florida has adopted this same rule at 62-710.210 FAC. Rayonier manages its Used Oil in accordance with these regulations. Used Oil is managed in a separate building with spill control until the oil is sampled and analyzed to prove it meets the definition of On-Specification which allows it to be burned on-site. The Used Oil is then transferred to the main #6 oil storage tank, from which it is eventually sent to a day tank and thence to a boiler. There is no reason to expect the Used Oil generated and burned in any future year will be any different than in 2004. Most of the Used Oil is hydraulic oil and gear box lubricating oil, and a very little engine crankcase oil. The Table below presents the throughput and emissions of those substances of which an analysis is required by 62-710.210 based on 8760 hrs per year.

Throughput	Arsenic (not detected)	Cadmium (not detected)	Chromium (not detected)	Lead (3 ppm avg 7 detects of 13 samples)	Total Halogens as Cl (241 ppm average of 9 detects of 13 samples)
6160 gal/yr	0 lbs/yr	0 lbs/yr	0 lbs/yr	0.157 lbs/yr	12.62 lbs/yr
0.703 gal/hr	0 lbs/hr	0 lbs/hr	0 lbs/hr	1.8E-05 lbs/hr	0.00144 lbs/hr

5. A spreadsheet is attached (Attachment 1) which includes the calculations and emissions factors utilized to provide the basis for this discussion on issue 5. This spreadsheet includes all calculations, emission factors and assumptions. It is apparent that production may not be the best surrogate for emissions because all emission points are equipped with emission reduction equipment, thus the relationship is not always one-to-one. There is no other surrogate and Rayonier is willing to maintain production as the surrogate. We discuss each of the manufacturing segments you mentioned in this request separately.

Pulping Operations
The sulfur dioxide and VOC's are the only pollutants emitted from the one pulping area vent. Sulfur dioxide is the chief pulping chemical in a sulfite mill and every attempt is made to capture and recycle it. There are four absorption towers in the pulping system that capture and recycle escaping sulfur dioxide, after which there is a final scrubber known in the permit as the Vent Gas Scrubber which polishes these collected gas streams before emission. Sulfur dioxide that is not recycled is lost to the process and must be made up by burning molten sulfur or purchasing very expensive liquid sulfur dioxide. The mill has economic incentives to collect sulfur dioxide.

Table 13 from Attachment 5 to the application reproduced in the attached spreadsheet (row #18), shows a steady decrease in sulfur dioxide emissions since 2000. This is due to improvements in the absorption systems limiting the amount of SO2 going to the vent gas scrubber. Nevertheless, the highest emissions in the last 5 years, which occurred in 2000/2001, was used as the baseline year because it calculates the greatest increase in emissions. By rights, Rayonier could use the same baseline years for sulfur dioxide that it used for VOC, 2003/2004, and the increase in sulfur dioxide emissions would calculate to 2.05 tons per year, down from 10.92 tons per year. We have maintained the 2000/2001 baseline for sulfur dioxide because it produces the most conservative analysis.

VOCs, 98 percent of which is methanol, are formed in the digestion process. The quantity of methanol produced depends on the grade of pulp being produced. However, Rayonier has always calculated these emissions based on the worst case grade thereby over estimating emissions. These VOCs pass through all the sulfur dioxide capture equipment including the vent gas scrubber but are captured by a new condenser installed to meet the new Part 63, Subpart S standards. The efficiency of the methanol capture depends on the amount of fresh water used in this new condenser which lowers gas temperature. Fresh water usage is always minimized to conserve ground water. Methanol emissions have been tested annually and have been found to be stable. This testing also checks the efficiency of the methanol condenser for a given exit gas temperature and fresh water flow rate.

The spreadsheet provides the production rate change history [row 4] and a copy of Table 13 from the application [row 18]. Also included is the pulping [vent gas scrubber] section of the AOR calculations for 2004 [row 74]. Following Table 13 is the Pulping System data [row 55 – 72].

Bleaching Operations
The parameters of interest for the bleaching operation are VOCs represented by methanol and CO. The spreadsheet section [row 252] under bleaching operations shows the Ton/yr VOC increase with production assuming no heat recovery from the hot caustic extraction stage emissions. As explained in the application a heat recovery condenser system will be installed which will capture and allow for the biological removal of the methanol.

CO emissions are explained in the application. The very conservative factor for CO emissions per ton of production is used to derive the table in the spreadsheet [row 252] under bleaching operations. The tables constructed in the spreadsheet show the production for 1996, 2003, 2004 and the proposed PSD tonnages. The information will not directly relate to that in Table 13 [row 224] since the changes in Table 13 are based on the baseline years, whereas the spreadsheet tables show changes from 1996.

Chemical Recovery Process
The parameters of concern are SO_2 and VOC. As discussed in the section on pulping, SO_2 is an integral part of the sulfite process and is captured and reused wherever possible. All of the process vents in the evaporator and recovery area are captured. They are piped to the recovery boiler scrubber for absorption and return to pulping liquor preparation in the acid plant as ammonium bisulfite. The emissions are again directly related to the capability of the absorption equipment and the amount of base applied to capture the SO_2. For the recovery process the base, ammonia is also used in the cooking process, so a high rate of SO_2 capture is financially beneficial. Therefore, there is no direct relationship between SO_2 emissions and production rate. However to answer the question presented, a table [row 263] is provided showing the potential for SO_2 losses from burning spent sulfite liquor with no SO_2 capture equipment.

VOC from the evaporators are chiefly methanol. Condensers now control methanol emissions. The attached spreadsheet provides VOC information from the 2004 AOR [rows 273 through 444]. The tonnage of VOC emitted from this area presented on a production basis is in the table at row 466 in the spreadsheet.

We disagree that the recovery boiler must be included in the netting analysis. In the application we pointed to the provision 40 CFR 52.21(b)(41)(ii)(c) which is part the federal New Source Review ("NSR") reform regulation and has been upheld in a recent D.C. Circuit Court of Appeals decision. Florida has proposed to adopt the federal rule, including this provision. The public hearing on the proposed rule is scheduled for

October 28 and Clean Air Act deadlines require the State of Florida to adopt its NSR rule revisions by December 31, 2005.

But we are not suggesting that the Department must "jump the gun" in implementing the above referenced provision out of the new rules package in order to recognize that a PSD emissions analysis of a "modification" must only include emission increases caused by a proposed physical change. In the Technical Support Document for its NSR rule changes, *Technical Support Document for the Prevention of Significant Deterioration and Nonattainment Area New Source Review Regulations, November 2002,* EPA recognized that the Clean Air Act and the implementing regulations require that there must be "a causal link between the proposed change and any post change increase in emissions" (at p. 1-4-37). Specifically, the definition of modification references "any physical change or change in the method of operation that would result in a significant net emissions increase . . . (at p. 1-4-37)." Thus, the "demand growth" exclusion that is a part of the existing federal NSR rules and is proposed to be included in the Florida rules is merely a codification of the definition of "modification" as set forth in the Clean Air Act and the implementing regulations. Accordingly, we have suggested that the proposed rule be referenced as an appropriate means of applying the causal standard that currently is mandated by the Clean Air Act.

6. With all things being approximately equal the emissions from one year to the next with the same number of operating hours will be approximately the same. However the Annual Operating report is based on the best information available when the report is prepared. As described for each pollutant below, new test or monitoring data became available and was used to calculate emission. Thus other factors are also involved in determining total emissions not just operating hours as demonstrated in the following review of the parameters in question.

This table summarized the emissions in Tons/year from the AORs for 2000-2004:

This table summarized the emissions in tons/year from the AORs for 2000-2004:

Recovery Boiler SSL Fired						
Parameter		**2004**	**2003**	**2002**	**2001**	**2000**
Net Production ADMT/yr		145,883	144,975	145,895	146,247	151,515
Production ADUBT/yr		223,276	223,692	217,383	223,669	214,703
Operating Hours / year		8,072	7,871	7,970	8,177	8,423
CO	Ton/yr	411	271	430	409	429
NOx	Ton/yr	2,070	916	904	925	1,032
PM	Ton/yr	84	48	77	212	194
PM10	Ton/yr	75	43	69	190	169

Carbon Monoxide
From the table it is evident that 2003 was the year with more unusual results. The attached spreadsheet (Attachment 2) has copies of the actual calculations provided to the FDEP for verification of the AOR. For the years 2000 through 2002 the CO emissions were based on the last good [operable meter reading] CO emissions data from the recovery boiler meter which were from 1999 at 187 ppm CO. In 2003 the meter was again operable and averaged 137 ppm CO for the year. In 2004 the meter averaged 195 ppm CO. The flue gas volumetric flow rate and the operating hours were similar for each year, so the CO concentration was the determining factor for emissions reported.

Nitrogen Oxides
For all the years from 1995 through 2003 the only NOx data available was from a 1995 stack test at 245 lb NOx / hr. In 2004 the recovery boiler emissions were tested for NOx at the same time as the annual particulate testing. During this testing the NOx was measured at 525 lb NOx/hr [605 ppmV NOx]. Since this was a considerable change from our historic emissions value, in 2005 NOx was again tested when the particulate testing was done. In 2005 the NOx averaged 600 ppmV NOx for the three one-hour tests. Therefore the mill is confident the 2004 AOR NOx emissions reported are correct.

Particulate and PM10
In 2002 the mill completed a program of changing out our mist filter candles with Monsanto polyester fiber units. As shown in the attached spreadsheet, the particulate emissions dropped from the 40-50 lb/hr range of 2000-2001 to the 15-25 range of 2002-2004. The 2005 stack test for PM was at 22 lb PM/hr. Therefore the normal PM emissions level with the new candles is between 45 and 85 Tons/year compared to 190 to 215 Tons/year earlier. Although there was a doubling of emissions between 2003 and 2004, this doubling was at a much lower level of emissions. The reason for the lower emission rate for 2003 at 13 lb PM/hr compared to 22-24 lb PM/hr for 2002, 2004 & 2005 is unknown, but the 22 lb PM/hr [84 Ton/yr] for 2004 is a representative level of PM emissions.

PM10 is calculated from PM and varies accordingly.

7. Other than CEM and CMS, the only required emissions testing under the mill's Title V permit is for particulate. Particulate testing notification is provided to the FDEP NE District Office verbally, via e-mail or via fax before each particulate testing. All particulate tests have been provided to the FDEP.

Attachment 5, appendix A of the application provided the source information for each parameter's emissions for 2000-2004. The following is a discussion of this source information and any additional testing that was completed.

Nitrogen Dioxide
In all cases of oil burning in the power boilers, the AP 42 factor [47 lb NOx / kgal oil] was used with the actual oil burned during the year to determine the Tons NOx/yr emitted.

For bark burning, NOx emissions before 2004 were from the AP 42 factor [0.22 lb NOx / MMBTU heat input from bark]. The bark heat input was calculated based on 5,000 BTU/lb wet bark. The quantity of bark burned per year for each boiler is calculated from steam output from the boiler divided by the boiler efficiency of 55% minus the heat input from oil for the year. This calculation is used since there is only one bark weightometer for the two boilers and no accurate way to determine how much of the bark goes to each boiler. The steam meter is very accurate and the efficiency has been determined over the years [and is common for this vintage and type of boiler]. All of these calculations are provided in spreadsheet form to the FDEP with each AOR submission.

In 2004 a NOx concentration analysis was run concurrently with the PM testing. The results are presented in the attached (Attachment 3) spreadsheet. The heat input rate calculations for the stack tests are also included on the spreadsheet. Based on these results there were 387 Tons NOx emitted in 2004. The calculations used to derive the 299 Tons NOx emitted in 2004 are thoroughly explained in the application. The reports for the 2004 and 2005 NOx tests are attached. All test runs have been included.

Carbon Monoxide, Sulfur Dioxide and Volatile Organic Carbon
There were no tests conducted for VOC and all calculations are based on AP-42 factors. The test results for CO and SO2 are included in the attached tables and test reports for 2004 and 2005.

8. Rayonier is purchasing this boiler from the salvage vendor, not from Smurfit. The limited records we have been able obtain were made available in the interest of determining the value in the existing boiler. Detailed maintenance records are much harder to obtain from a mill that has been closed for at least 5 years. Rayonier was made aware of modifications made to bring the boiler's particulate emissions into compliance. However, these costs are not pertinent as at that time Smurfit controlled particulates with a wet scrubber. Rayonier is proposing to use an ESP for particulate control and the wet scrubber for SO_2 control. Per guidance, control equipment is not included in the reconstruction analysis.

To the extent your question anticipates the issue of "aggregation" for purposes of crossing the 50 percent threshold leading to new source review, it is patently clear that anything the previous owner did is completely unrelated to the conversion Rayonier is making. Therefore, aggregation can not be an issue.

You have asked us to verify the conversion cost from a stoker to bubbling bed boiler. Rayonier now has a contract for this conversion so we are as certain as we can be of the costs presented in the reconstruction analysis provided in Attachment 5 to the Application.

In regard to the U.S. Sugar facility in Clewiston, it should be remembered that the facility is only a 600 psi boiler. The facility proposed for Rayonier at Fernandina, No. 6 boiler, is a 900 psi boiler. There is considerable difference in the metallurgy required for the higher pressure boiler, also pipe and welding thickness are greater and the higher pressure required post-weld heat treating. The steam drum alone is 1 inch thicker in the 900 psi boiler. This is a large diameter vessel inside the boiler adding considerably to the cost. Steel and concrete prices have increase dramatically over the past several years since the Clewiston facility was constructed. With the recent energy crises further inflation is expected. Though we do not know the cost of the Clewiston facility, from our experience in negotiating for these materials it is doubtful this facility could be built for $40 million today.

9. As explained on pages 11 and 12 of the Project Description, Attachment 5 to the Application, the maximum emissions could not exceed the applicable New Source Performance Standards for the 1983 boiler. These limits were given in Table 3. No emission rates proposed for the converted boiler are greater than these emissions. These proposed rates were also given in Table 3. Table 3 is reproduced here for your convenience. It can be confidently concluded the emission rates for the new boiler will not exceed those of the old 1983 boiler.

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

Pollutant	Limit in lbs/mmBtu unless indicated	Expected New Limit in lbs/mmBtu unless indicated
PM	0.10	0.07
Opacity	=<20% except 6/hour<27%	=<20% except 6/hr<27%
SO_2 solid fossil fuel	1.2	NA
SO_2 liquid fossil fuel	0.8	0.8
NOx	0.3	0.3[1]

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

It is noted that the Department has proposed language for its NSR reform rule at 62-204.200(1)(b) that unit-specific allowable emissions for an emissions unit are equivalent to the actual emissions for the emissions unit provided that such unit- specific allowable emissions limits are federally enforceable.

10. A comparison of the emission rates and dispersion characteristics of the existing stack with the proposed stack was provided in letter faxed from David Tudor to you and Bruce Mitchell dated October 12, 2005. That comparison is provided again below. It demonstrates there is no reason to repeat modeling this source.

In regard to the modeling questions, to save the Department modelers a little time, the table below presents the stack parameters in the modeling done in 1992 and those for the new boiler. This modeling was submitted to address the elevated ambient SO_2 levels due to downwashing Rayonier boiler stacks found by the modeling done for the Smurfit project. The five years of meteorological data were 1982 – 1986. As you can see the new boilers stack height and stack gas velocity are higher, stack exit temperature is about the same as there are wet scrubbers on the old boilers and the new boiler, and SO_2 emissions rates are lower than in the existing units. Both the remaining emissions at the facility, recovery boiler and vent gas scrubber were modeled at permitted levels and those have not changed. Every parameter used in modeling would predict lower SO_2 impacts. The new stack is less than 600 feet from the old stack. There is little reason to remodel.

	#1&2	**#3**	**#6**
stack height (meters)	37.2	37.2	57.91
stack temp. (deg K)	336	329	338
stack velocity (m/sec)	9.75	9.75	11.8
SO2 emission (gm/sec)	81.18	40.48	7.42

11. Steam data began being collected automatically and digitally about October 13, 2000. Data prior to October 2000 was manually collected and was not readily available. To use it would require manual entry of many data points, a process prone to error. The data was collected at regular intervals and written on paper. We elected to omit calculations for the year 2000 since only one quarter of data was available digitally.

12. The emission factors, activity factors and annual estimates for each boiler are provided in Attachment 1 for issue number 5. The power boiler calculations are presented on rows 535 through 1416.

The maximum steam production for 2003 and 2004 are provided below:

Maximum Steam Production 1000 lb/hr				
Year	No. 1 PB	No. 2 PB	No. 3 PB	Total PB
2003	96	117	136	344
2004	94	109	137	339
Capacity	120	120	135	375

The maximum production level was very consistent for the two years. Maximum production is generally required only when the recovery boiler is down for repair. When this happens the oil usage for the three power boilers increases by a factor of 2 to 3 over the average and the bark usage drops to about 70% of average usage. The bark usage drops because the boilers become air limited when they are maximized for steam production and it takes less air to burn oil.

13. As you know, without SO_2 CEMs we are not allowed to take credit for SO_2 removal. We pay fees assuming the entire sulfur input from the oil is converted into SO_2. For estimating emissions we have generally used 90% removal. Both scrubbers, all three boilers, were last tested in 2004. The average sulfur content of the May deliveries was 1.64 % sulfur. The results of the sulfur dioxide collection efficiency is reflected in the table below. These tests certainly justify the 90% removal efficiency. The continuous efficiency is of course unknown as the pH of the scrubbing media varies.

Scrubber Efficiencies

test date	run	start time	end time	SO_2 ppmv	flow dscfm	bbl oil	removal eff
10-Jun-04	A1	12:00	13:00	4.01	92695.6	110	0.994
10-Jun-04	A2	14:41	15:41	4.44	100367.6	114	0.994
10-Jun-04	A3	17:34	18:34	4.1	90347	105	0.994
9-Jun-04	B1	12:29	13:20	0.78	98106.4	41	0.997
9-Jun-04	B2	15:00	15:56	0.43	89716.4	31	0.998
9-Jun-04	B3	17:51	18:58	0.64	90837.6	22	0.995

14. No new federal regulations have been promulgated implementing more stringent controls for sulfur dioxide. The new regulations only applied to pulping emissions of volatile organic HAPs as measured by methanol. The years 2000, 2001 were used for baseline for SO_2 emissions because they provided a more conservative analysis. By using 2003, 2004 as the baseline years the increase drops from 10.93 to 2.05 TPY.

15. The potential capacity of a complex facility can not simply be arrived at by some sort of engineering calculation. It is more than just the operating capacity of the bottleneck operations, and greatly depends on the amount of maintenance and operating expense the facility can incur, which depends on market conditions. Examining historical record prior to the installation of No.6 digester, the most pulp produced in any year was 150,000 in 1996. This was the baseline year. However, the mill makes many grades of pulp only to order. Almost no pulp is made on speculation. The annual production experience is mostly dependant on market conditions, not potential capacity. The most tons produced in any month was in 1988 when 16,733 tons were produced giving an annual capacity of 167,733 tons per year. The most tons produced in any day was 549, which at 350

operating days gives and annual capacity to 192,150 tons per year. Prior to No. 6 digester the most tons in any week was in 1992 when the mill produced 3432 tons calculating to 171,600 tons per year. It should be clear that the capacity prior to No. 6 digester installation exceeded the annual production in this request.

16. Our response to question 10 demonstrates that every parameter that would affect modeled ambient concentrations would produce lower impacts than those shown in the modeling previously submitted. That modeling included the Smurfit-Stone Fernandina Beach mill emissions, and other nearby major sources. The interaction of all nearby major sources with the Rayonier's plume is analyzed in this modeling. Since the pulp mill in St Marys subsequently closed, but was included in this modeling, predicted impact will be even less. There is no need to do further modeling.

I hope this answers all you questions and you can proceed to issue this construction permit. If you have questions regarding this response please try to contact David Tudor at (904)277-1452 or Dick Hopper at (904)277-1480.

Yours very truly,

Fred J Perrett

F. J. Perrett
General Manager

cc: Christopher Kirts - FDEP
Trina Vielhauer - DARM

ATTACHMENT 3

	Date	O2 %	NOX ppmV,dry	SO2 ppmV,dry	CO ppmV,dry	PM g/dscm 8%O2	PM lb/hr	Gas Flow dscf/m
A Scrubber	6/10/2004	11.4	79.7	3.7	225.7	0.121	31.0	92,696
	6/10/2004	12.3	86.3	4.1	175.7	0.164	41.2	100,363
	6/10/2004	11.8	79.4	3.7	248.6	0.250	57.1	90,347
	Average	11.8	81.8	3.8	216.7	0.179	43.1	94,468
B Scrubber	6/9/2004	11.5	53.8	0.8	133.3	0.079	20.9	98,106
	6/9/2004	12.4	62.1	0.3	115.8	0.215	47.6	89,716
	6/9/2004	12.4	63.7	0.4	150.6	0.154	34.4	90,838
	Average	12.1	59.9	0.5	133.2	0.149	34.3	92,887

A Scrubber			
81.8	ppmV NOX 2004	385	dscf/mole
94,468	dscf/m flue gas	46	lb NO2/mole NO2
7.73	dscf/min NOX	55.40	lb NOX/hr
		224	T NOX/yr
3		1,330	lb NOX/day

B Scrubber			
59.9	ppmV NOX 2004	385	dscf/mole
92,887	dscf/m flue gas	46	lb NO2/mole NO2
5.56	dscf/min NOX	40	lb NOX/hr
		163	T NOX/yr
		957	lb NOX/day

AOR Total		387	T NOX/yr

Attach3 Quest #7 NOX Stack Tests Power Boilers 2004

"A" SCRUBBER STACK TEST ANALYSIS for 10-Jun-04

Steam Output from No. 2 Power Boiler

Run Number	Steam Production [1000 lb./hr. of 1000 BTU/lb. Steam] Power Boiler No. 1	Power Boiler No. 2	Total
A-1	90	105	195
A-2	100	97	198
A-3	93	105	197
Average	95	101	196
Capacity	120	120	240
A Scrubber Actual Total % of Capacity =			82%

Oil Input to Boiler

Run Number	Power Boiler No. 1 Gal. Oil	Test Min.	BTU/gal	MMBTU/hr from Oil	Power Boiler No. 2 Gal. Oil	Test Min.	BTU/gal	MMBTU/hr from Oil	Test Result per Stack test
A-1	718	61	155,833	110	0	61	155833	0.0	31.0
A-2	756	62	155833	114	0	62	155833	0.0	41.2
A-3	676	60	155,833	105	0	60	155,833	0.0	57.1
Average	737	62	155,833	112	0	62	155,833	0	43.1
Permit Maximum	[mmBTU/hr]			185				184	

Allowable Particulate Emissions Calculation

Test total BTU Input from Oil for B Scrubber	112	MM BTU/hr.	
Maximum Steam Output from 1 & 2 PB	240,000	lb./hr. [1000 BTU Steam]	
Test Operating Rate	82%		
Test Steam Output Rate	196,381	lb./hr.	
Boiler Efficiency on Oil	65%		
Test Steam from Oil	72,831	lb./hr. [total input from oil x Eff. on oil]	
Test Steam from Bark [by difference]	123,550	lb./hr.	
Boiler Efficiency on Bark	55%	Permit Max.	
Test Heat Input from Bark	225	mmBTU/h 218	Maximum By Permit
Emissions Limit Factor for Bark	0.23	lb. PM/MMBTU	
Emissions Limit Factor for Oil	0.086	lb. PM/MMBTU	
Allowable Emissions from Bark	51.7	lb. PM/hr [emissions factor x heat input]	50.6 #2 Bark Only
Allowable Emissions from Oil	9.6	lb. PM/hr [emissions factor x heat input]	15.2 #2 Oil Only
Total Allowable Emissions for A Scrubber	61.3	lb. PM/hr. (Including Oil Emissions)	16.0 #1 Oil Only
Total Allowable Emissions for A Scrubber	61.3	lb. PM/hr. (By Oil Emissions Factor or Permit)	
Actual emissions for A Scrubber 10-Jun-04 Test	43.1	lb. PM/hr.	

Attach3 Quest #7 NOX Stack Tests Power Boilers 2004

"B" SCRUBBER STACK TEST ANALYSIS for 06/09/04

Steam Output from No. 3 Power Boiler

Run Number	Steam Production [1000 lb./hr. of 1000 BTU/lb. Steam] Power Boiler No. 3
B1	122
B2	135
B3	116
Average	125
Capacity	135

B Scrubber Actual Total % of Capacity = 92%

Oil Input to Boiler

Run Number	Power Boiler No. 3 Gal. Oil	Test Min.	BTU/gal	MMBTU/hr from Oil	Test Result per Stack test
B1	231	52	155,833	41	20.9
B2	185	56	155,833	31	47.6
B3	143	61	155,833	22	34.4
Average	186	56	155,833	31	34.3
Permit Maximum		[mmBtu/hr]		207	

Allowable Particulate Emissions Calculation

Test total BTU Input from Oil for B Scrubber		31.4	MM BTU/hr.			
Maximum Steam Output from 3 PB		135,000	lb./hr. [1000 BTU Steam]			
Test Operating Rate		92%				
Test Steam Output Rate		124,648	lb./hr.			
Boiler Efficiency on Oil		65%				
Test Steam from Oil		20,411	lb./hr. [total input from oil x Eff. on oil]			
Test Steam from Bark [by difference]		104,237	lb./hr.			
Boiler Efficiency on Bark		55%		Permit Max.		
Test Heat Input from Bark		190	mmBTU/hı	245		
Emissions Limit Factor for Bark		0.207	lb. PM/MMBTU		Permit	
Emissions Limit Factor for Oil		0.086	lb. PM/MMBTU		Maximum	
Allowable Emissions from Bark		39.2	lb. PM/hr [emissions factor x heat input]		50.6	#3Bark Only
Allowable Emissions from Oil		2.7	lb. PM/hr [emissions factor x heat input]		16.7	#3 Oil Only
Total Allowable Emissions for B Scrubber		41.9	lb. PM/hr. (Including Oil Emissions)			
Total Allowable Emissions for B Scrubber		41.9	lb. PM/hr. (By Oil Emissions Factor or Permit)			
Actual emissions for B Scrubber	Test	34.3	lb. PM/hr.			

ATTACHMENT 2

Recovery Boiler SSL Fired						
Parameter		2004	2003	2002	2001	2000
Net Production ADMT/yr		145883	144975	145895	146247	151515
Production ADUBT/yr		223,276	223,692	217,383	223,669	214,703
Operating Hours / year		8,072	7,871	7,970	8,177	8,423
CO	Ton/yr	411	271	430	409	429
NOx	Ton/yr	2,070	916	904	925	1,032
PM	Ton/yr	84	48	77	212	194
PM10	Ton/yr	75	43	69	190	169

CO 2004	No factor for spent sulfite liquor (SSL).	
ppm (CO)	195	"Recovery Boiler Hourly" report for 2004.
dscfm (average)	121,096	From this year's Stack Test Data.
dscf/mol @ 20C	385	
Tons (CO)/yr [Total]	416	
Tons (CO)/yr [Oil]	5	
Tons (CO)/yr [SSL]	411	
lbs (CO)/day [SSL]	2,442	
Example Calculation:		
Tons (CO)/yr [Total]	= [CO Conc. (ppm)] x [MW(CO)] / [2000 lbs/ton] x [dscf/min] / [dscf/mol] x 60 min/hr x [Hrs of Oper (hrs/yr)]	

CO 2003	No factor for spent sulfite liquor (SSL).	
ppm (CO)	137	"Recovery Boiler Hourly" report for 2003.
dscfm (average)	117,393	From this year's Stack Test Data.
dscf/mol @ 20C	385	
Tons (CO)/yr [Total]	276	
Tons (CO)/yr [Oil]	5	
Tons (CO)/yr [SSL]	271	
lbs (CO)/day [SSL]	1,653	
Example Calculation:		
Tons (CO)/yr [Total]	= [CO Conc. (ppm)] x [MW(CO)] / [2000 lbs/ton] x [dscf/min] / [dscf/mol] x 60 min/hr x [Hrs of Oper (hrs/yr)]	

Attach2 Quest #6 calcs 2005-10

CO 2002	No factor for spent sulfite liquor (SSL).	
ppm (CO)	187	"Recovery Boiler Hourly" report for 1999 - 307 entries - meter not operable in 2001 or 2002
dscfm (average)	134,513	From this year's Stack Test Data.
dscf/mol @ 20C	385	
Tons (CO)/yr [Total]	437	
Tons (CO)/yr [Oil]	8	
Tons (CO)/yr [SSL]	430	
lbs (CO)/day [SSL]	2,588	
Example Calculation:		
Tons (CO)/yr [Total]	= [CO Conc. (ppm)] x [MW(CO)] / [2000 lbs/ton] x [dscf/min] / [dscf/mol] x 60 min/hr x [Hrs of Oper (hrs/yr)]	

CO 2001	No factor for spent sulfite liquor (SSL).	
ppm (CO)	187	"Recovery Boiler Hourly" report for 1999 - 307 entries - meter not operable in 2001
dscfm (average)	125,172	From this year's Stack Test Data.
dscf/mol @ 20C	385	
Tons (CO)/yr [Total]	418	
Tons (CO)/yr [Oil]	8	
Tons (CO)/yr [SSL]	409	
lbs (CO)/day [SSL]	2,403	
Example Calculation:		
Tons (CO)/yr [Total]	= [CO Conc. (ppm)] x [MW(CO)] / [2000 lbs/ton] x [dscf/min] / [dscf/mol] x 60 min/hr x [Hrs of Oper (hrs/yr)]	

CO 2000	No factor for spent sulfite liquor (SSL).	
ppm (CO)	187	"Recovery Boiler Hourly" report for 1999 307 entries - meter not operable in 2000
dscfm (average)	127,672	From this year's Stack Test Data.
dscf/mol @ 20C	385	
Tons (CO)/yr [Total]	439	
Tons (CO)/yr [Oil]	9	
Tons (CO)/yr [SSL]	429	
lbs (CO)/day [SSL]	2,447	
Example Calculation:		
Tons (CO)/yr [Total]	= [CO Conc. (ppm)] x [MW(CO)] / [2000 lbs/ton] x [dscf/min] / [dscf/mol] x 60 min/hr x [Hrs of Oper (hrs/yr)]	

Attach2 Quest #6 calcs 2005-10

NOX 2004
Stack Tests 2004

605	ppmV NOX 2004	385	dscf/mole	
121,096	dscf/m flue gas	46	lb NO2/mole NO2	
73	dscf/min NOX	525	lb NOX/hr	minus recovery oil NOX
		2,120	T NOX/yr	2,070
		12,608	lb NOX/day	12,312

NOx 2003

lbs (NOx)/hr	245	Average from Stack Test Data from 1995
Tons (NOx)/yr	916	
lbs (NOx)/day	5,588	

Example Calculation:
Tons (NOx)/yr = [[lbs (NOx)/hr] x [Hours of Oper (hrs/yr)] / [2000 lbs/ton]] - [Tons Nox/yr from Oil]
lbs (NOx)/day = [Tons (NOx)/yr] / [Days of Oper (days/yr)] x [2000 lbs/ton]

NOx 2002

lbs (NOx)/hr	245	Average from Stack Test Data from 1995
Tons (NOx)/yr	904	
lbs (NOx)/day	5,443	

Example Calculation:
Tons (NOx)/yr = [[lbs (NOx)/hr] x [Hours of Oper (hrs/yr)] / [2000 lbs/ton]] - [Tons Nox/yr from Oil]
lbs (NOx)/day = [Tons (NOx)/yr] / [Days of Oper (days/yr)] x [2000 lbs/ton]

NOx 2001

lbs (NOx)/hr	245	Average from Stack Test Data from 1995
Tons (NOx)/yr	925	
lbs (NOx)/day	5,429	

Example Calculation:
Tons (NOx)/yr = [[lbs (NOx)/hr] x [Hours of Oper (hrs/yr)] / [2000 lbs/ton]] - [Tons Nox/yr from Oil]
lbs (NOx)/day = [Tons (NOx)/yr] / [Days of Oper (days/yr)] x [2000 lbs/ton]

NOx 2000

lbs (NOx)/hr	245	Average from Stack Test Data from 1995
Tons (NOx)/yr	1,032	
lbs (NOx)/day	5,880	

Example Calculation:
Tons (NOx)/yr = [lbs (NOx)/hr] x [Hours of Oper (hrs/yr)] / [2000 lbs/ton]
lbs (NOx)/day = [Tons (NOx)/yr] / [Days of Oper (days/yr)] x [2000 lbs/ton]

PM 2004			
lbs (PM)/hr		24	From Stack Test Data. (No oil burning during these tests.)
Tons (PM)/yr	includes test rate ratio	84	
lbs (PM)/day		500	
Example Calculation:			
Tons (PM)/yr	= [lbs (PM)/hr] x [Hours of Oper (hrs/yr)] x [test rate ratio to average rate] / [2000 lbs/ton]		
lbs (PM)/day	= [Tons (PM)/yr] / [Days of Oper (days/yr)] x [2000 lbs/ton]		

PM 2003			
lbs (PM)/hr		13	From Stack Test Data. (No oil burning during these tests.)
Tons (PM)/yr	includes test rate ratio	48	
lbs (PM)/day		293	
Example Calculation:			
Tons (PM)/yr	= [lbs (PM)/hr] x [Hours of Oper (hrs/yr)] x [test rate ratio to average rate] / [2000 lbs/ton]		
lbs (PM)/day	= [Tons (PM)/yr] / [Days of Oper (days/yr)] x [2000 lbs/ton]		

PM 2002			
lbs (PM)/hr		22	From Stack Test Data. (No oil burning during these tests.)
Tons (PM)/yr	includes test rate ratio	77	
lbs (PM)/day		465	
Example Calculation:			
Tons (PM)/yr	= [lbs (PM)/hr] x [Hours of Oper (hrs/yr)] x [test rate ratio to average rate] / [2000 lbs/ton]		
lbs (PM)/day	= [Tons (PM)/yr] / [Days of Oper (days/yr)] x [2000 lbs/ton]		

PM 2001			
lbs (PM)/hr		52	From Stack Test Data. (No oil burning during these tests.)
Tons (PM)/yr		212	
lbs (PM)/day		1,246	
Example Calculation:			
Tons (PM)/yr	= [lbs (PM)/hr] x [Hours of Oper (hrs/yr)] / [2000 lbs/ton]		
lbs (PM)/day	= [Tons (PM)/yr] / [Days of Oper (days/yr)] x [2000 lbs/ton]		

PM 2000			
lbs (PM)/hr		46	From Stack Test Data. (No oil burning during these tests.)
Tons (PM)/yr		194	
lbs (PM)/day		1,106	
Example Calculation:			
Tons (PM)/yr	= [lbs (PM)/hr] x [Hours of Oper (hrs/yr)] / [2000 lbs/ton]		
lbs (PM)/day	= [Tons (PM)/yr] / [Days of Oper (days/yr)] x [2000 lbs/ton]		

PROJECT PARTICIPANTS

STACS

Bill Mayhew	Project Manager
Geoff Johnson	Environmental Scientist
Jon Proulx	Environmental Scientist
Lee Garcia	Environmental Scientist
Aaron Harden	Document Coordinator

RAYONIER

Dick Hopper	Environmental Director
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APPENDIX D
PROJECT PARTICIPANTS

"B" SCRUBBER STACK TEST ANALYSIS for 14-Jul-05

Steam Output from No. 3 Power Boiler

Run Number	Steam Production [1000 lb./hr. of 1000 BTU/lb. Steam] Power Boiler No. 3
1	116
2	121
3	129
Average	122
Capacity	135

B Scrubber Actual Total % of Capacity = 91%

Oil Input to Boiler

Power Boiler No. 3					
Run Number	Gal. Oil	Test Min.	BTU/gal	MMBTU/hr from Oil	Test Result per Stack test
1	894.6	60	163,105	146	na
2	919.8	61	163,105	148	na
3	936.6	61	163,105	150	na
Average	917	61	163,105	148	na
Permit Maximum [mmBtu/hr]				207	

Allowable Particulate Emissions Calculation

Test total BTU Input from Oil for B Scrubber	148	MM BTU/hr.	
Maximum Steam Output from 3 PB	135,000	lb./hr. [1000 BTU Steam]	
Test Operating Rate	91%		
Test Steam Output Rate	122,241	lb./hr. [135,000 x test operating rate]	
Boiler Efficiency on Oil	65%		
Test Steam from Oil	96,143	lb./hr. [total input from oil x Eff. on oil]	
Test Steam from Bark [by difference]	26,098	lb./hr.	
Boiler Efficiency on Bark	55%	Permit Max.	
Test Heat Input from Bark	47	mmBTU/hr 245	
Emissions Factor for Bark	0.207	lb. PM/MMBTU	Permit Maximum
Emissions Factor for Oil	0.086	lb. PM/MMBTU	
Allowable Emissions from Bark	9.8	lb. PM/hr [emissions factor x heat input]	50.6
Allowable Emissions from Oil	12.7	lb. PM/hr [emissions factor x heat input]	16.7
Total Allowable Emissions for B Scrubber	22.5	lb. PM/hr.	(Including Oil Emissions)
Total Allowable Emissions for B Scrubber	22.5	lb. PM/hr.	(By Oil Emissions Factor or Permit)
Actual emissions for B Scrubber 14-Jul-05 Test	na	lb. PM/hr.	

"B" SCRUBBER STACK TEST ANALYSIS for 14-Jul-05

Steam Output from No. 3 Power Boiler

Run Number	Steam Production [1000 lb./hr. of 1000 BTU/lb. Steam] Power Boiler No. 3
3	129
Average	129
Capacity	135

B Scrubber Actual Total % of Capacity = 96%

Oil Input to Boiler

	Power Boiler No. 3			
Run Number	Gal. Oil	Test Min.	BTU/gal	MMBTU/hr from Oil
3	937	61	163,105	150
Average	937	61	163,105	150

Permit Maximum on Oil	[mmBtu/hr]	207
Permit Maximum on Bark	[mmBtu/hr]	245

Allowable Particulate Emissions Calculation

Test total BTU Input from Oil for B Scrubber	150	MM BTU/hr.		
Maximum Steam Output from 3 PB	135,000	lb./hr. [1000 BTU Steam]		
Test Operating Rate	96%			
Test Steam Output Rate	129,246	lb./hr. [135,000 x test operating rate]		
Boiler Efficiency on Oil	65%			
Test Steam from Oil	97,669	lb./hr. [total input from oil x Eff. on oil]		
Test Steam from Bark [by difference]	31,577	lb./hr.		
Boiler Efficiency on Bark	55%	Permit Max.		
Test Heat Input from Bark	57	mmBTU/hr. **245**		
Emissions Factor for Bark	0.207	lb. PM/MMBTU	Permit Maximum	
Emissions Factor for Oil	0.086	lb. PM/MMBTU		
Allowable Emissions from Bark	11.9	lb. PM/hr [emissions factor x heat input]	50.6	#3Bark Only
Allowable Emissions from Oil	12.9	lb. PM/hr [emissions factor x heat input]	16.7	#3 Oil Only
Total Allowable Emissions for B Scrubber	24.8	lb. PM/hr.	(Including Oil Emissions)	
Total Allowable Emissions for B Scrubber	24.8	lb. PM/hr.	(By Oil Emissions Factor or Permit)	
Actual emissions for B Scrubber 14-Jul-05 Test	na	lb. PM/hr.		

"B" SCRUBBER STACK TEST ANALYSIS for 14-Jul-05

Steam Output from No. 3 Power Boiler

Run Number	Steam Production [1000 lb./hr. of 1000 BTU/lb. Steam] Power Boiler No. 3
2	121
Average	121
Capacity	135

B Scrubber Actual Total % of Capacity = 90%

Oil Input to Boiler

Run Number	Power Boiler No. 3 Gal. Oil	Test Min.	BTU/gal	MMBTU/hr from Oil
2	919.8	61	163,105	148
Average	920	61	163,105	148

Permit Maximum on Oil	[mmBtu/hr]	207
Permit Maximum on Bark	[mmBtu/hr]	245

Allowable Particulate Emissions Calculation

Test total BTU Input from Oil for B Scrubber	148	MM BTU/hr.		
Maximum Steam Output from 3 PB	135,000	lb./hr. [1000 BTU Steam]		
Test Operating Rate	90%			
Test Steam Output Rate	121,377	lb./hr. [135,000 x test operating rate]		
Boiler Efficiency on Oil	65%			
Test Steam from Oil	95,917	lb./hr. [total input from oil x Eff. on oil]		
Test Steam from Bark [by difference]	25,460	lb./hr.		
Boiler Efficiency on Bark	55%	Permit Max.		
Test Heat Input from Bark	46	mmBTU/hr. 245		
Emissions Factor for Bark	0.207	lb. PM/MMBTU	Permit Maximum	
Emissions Factor for Oil	0.086	lb. PM/MMBTU		
Allowable Emissions from Bark	9.6	lb. PM/hr [emissions factor x heat input]	50.6	#3Bark Only
Allowable Emissions from Oil	12.7	lb. PM/hr [emissions factor x heat input]	16.7	#3 Oil Only
Total Allowable Emissions for B Scrubber	22.3	lb. PM/hr.	(Including Oil Emissions)	
Total Allowable Emissions for B Scrubber	22.3	lb. PM/hr.	(By Oil Emissions Factor or Permit)	
Actual emissions for B Scrubber 14-Jul-05 Test	na	lb. PM/hr.		

"B" SCRUBBER STACK TEST ANALYSIS for 14-Jul-05

Steam Output from No. 3 Power Boiler

Run Number	Steam Production [1000 lb./hr. of 1000 BTU/lb. Steam] Power Boiler No. 3
1	116
Average	116
Capacity	135

B Scrubber Actual Total % of Capacity = 86%

Oil Input to Boiler

	Power Boiler No. 3			
Run Number	Gal. Oil	Test Min.	BTU/gal	MMBTU/hr from Oil
1	894.6	60	163,105	146
Average	895	60	163,105	146

Permit Maximum on Oil	[mmBtu/hr]	207
Permit Maximum on Bark	[mmBtu/hr]	245

Allowable Particulate Emissions Calculation

Test total BTU Input from Oil for B Scrubber	146	MM BTU/hr.		
Maximum Steam Output from 3 PB	135,000	lb./hr. [1000 BTU Steam]		
Test Operating Rate	86%			
Test Steam Output Rate	116,100	lb./hr. [135,000 x test operating rate]		
Boiler Efficiency on Oil	65%			
Test Steam from Oil	94,844	lb./hr. [total input from oil x Eff. on oil]		
Test Steam from Bark [by difference]	21,256	lb./hr.		
Boiler Efficiency on Bark	55%	Permit Max.		
Test Heat Input from Bark	39	mmBTU/hr. **245**		
Emissions Factor for Bark	0.207	lb. PM/MMBTU	Permit	
Emissions Factor for Oil	0.086	lb. PM/MMBTU	Maximum	
Allowable Emissions from Bark	8.0	lb. PM/hr [emissions factor x heat input]	50.6	#3Bark Only
Allowable Emissions from Oil	12.5	lb. PM/hr [emissions factor x heat input]	16.7	#3 Oil Only

Total Allowable Emissions for B Scrubber	20.5	lb. PM/hr.	(Including Oil Emissions)
Total Allowable Emissions for B Scrubber	20.5	lb. PM/hr.	(By Oil Emissions Factor or Permit)
Actual emissions for B Scrubber 14-Jul-05 Test	na	lb. PM/hr.	

Power Boilers Scrubber Test

	Power Boiler Scrubber			**"B"**			
	Date			14-Jul-05			
	Run #		B #	3		0	
	Start of Test		*End of Test*		*Totals*	*Time*	
	hours	min	hours	min	min	*corrected*	
Time	11	38	12	39	61	0.98361	
Boiler No. 3							
Steam Flow Integrator (x 1000)	589.1		720.5		131400	129246	lb/hr
Steam Temperature ($^{\circ}$ F)___	765.1		763.8		764.45		
Drum Pressure (psig.)_____	511.9		501.9		506.9		
Oil Flow Intergrator (bbl.)__	98.6		120.9		22.3	921.246	gal/hr
*Steam Flow (lb/hr x 1000)_*	128.4		124.2		126300		
Oil Flow (gpm)__________	15.5		15.5		15.5		
Bark Integrator	69.4		80.2		10.8	11	wet/tons/hr
Bark to Boiler:	Num.(s)	3	And / or	___			
Scrubber "B" pH	5.0		5.0		5.00		

Power Boilers Scrubber Test

Power Boiler Scrubber **"B"**
Date 14-Jul-05
Run # B # 2 0

Boiler No. 3

	Start of Test hours	min	*End of Test* hours	min	*Totals* min	*Time corrected*	
Time	10	18	11	19	61	0.98361	
Steam Flow Integrator (x 1000)	427.6		551		123400	121377	lb/hr
Steam Temperature (° F)	753.5		770		761.75		
Drum Pressure (psig.)	414		528.1		471.05		
Oil Flow Intergrator (bbl.)	70.7		92.6		21.9	904.721	gal/hr
Steam Flow (lb/hr x 1000)	140.5		110.6		125550		
Oil Flow (gpm)	14.7		15.9		15.3		
Bark Integrator	50.9		63.7		12.8	13	wet/tons/hr
Bark to Boiler:	Num.(s)	3	And / or				
Scrubber "B" pH	5.0		5.1		5.1		

Power Boilers Scrubber Test

Power Boiler Scrubber		**"B"**	
Date		14-Jul-05	
Run #	B #	1	

	Start of Test		End of Test		Totals	Time	
	hours	min	hours	min	min	corrected	
Time	9	01	10	01	60	1	
Boiler No. 3							
Steam Flow Integrator (x 1000)	273.7		389.8		116100	116100	lb/hr
Steam Temperature (° F)	768.4		751.2		759.8		
Drum Pressure (psig.)	534.8		532.9		533.85		
Oil Flow Intergrator (bbl.)	43.7		65		21.3	894.6	gal/hr
Steam Flow (lb/hr x 1000)	127.8		120		123900		
Oil Flow (gpm)	14.8		14.7		14.75		
Bark Integrator	35		48.1		13.1	13	wet/tons/hr
Bark to Boiler: Num.(s)	3	And / or					
Scrubber "B" pH	5.0		5.0		5.0		

"B" SCRUBBER STACK TEST ANALYSIS for 8-Jul-05

Steam Output from No. 3 Power Boiler

Run Number	Steam Production [1000 lb./hr. of 1000 BTU/lb. Steam] Power Boiler No. 3
1	124
2	126
Average	125
Capacity	135

B Scrubber Actual Total % of Capacity = 93%

Oil Input to Boiler

Run Number	Power Boiler No. 3 Gal. Oil	Test Min.	BTU/gal	MMBTU/hr from Oil	Test Result per Stack test
1	785.4	60	158,104	124	na
2	819	62	158,104	125	
Average	802	61	158,104	125	na
Permit Maximum [mmBtu/hr]				207	

Allowable Particulate Emissions Calculation

Test total BTU Input from Oil for B Scrubber	125	MM BTU/hr.	
Maximum Steam Output from 3 PB	135,000	lb./hr. [1000 BTU Steam]	
Test Operating Rate	93%		
Test Steam Output Rate	125,242	lb./hr. [135,000 x test operating rate]	
Boiler Efficiency on Oil	65%		
Test Steam from Oil	81,083	lb./hr. [total input from oil x Eff. on oil]	
Test Steam from Bark [by difference]	44,159	lb./hr.	
Boiler Efficiency on Bark	55%	Permit Max.	
Test Heat Input from Bark	80	mmBTU/hr **245**	
Emissions Factor for Bark	0.207	lb. PM/MMBTU	Permit
Emissions Factor for Oil	0.086	lb. PM/MMBTU	Maximum
Allowable Emissions from Bark	16.6	lb. PM/hr [emissions factor x heat input]	50.6
Allowable Emissions from Oil	10.7	lb. PM/hr [emissions factor x heat input]	16.7
Total Allowable Emissions for B Scrubber	27.3	lb. PM/hr. (Including Oil Emissions)	
Total Allowable Emissions for B Scrubber	27.3	lb. PM/hr. (By Oil Emissions Factor or Permit)	
Actual emissions for B Scrubber 8-Jul-05 Test	na	lb. PM/hr.	

"B" SCRUBBER STACK TEST ANALYSIS for 8-Jul-05

Steam Output from No. 3 Power Boiler

Run Number	Steam Production [1000 lb./hr. of 1000 BTU/lb. Steam] Power Boiler No. 3
2	126
Average	126
Capacity	135

B Scrubber Actual Total % of Capacity = 94%

Oil Input to Boiler

Run Number	Power Boiler No. 3 Gal. Oil	Test Min.	BTU/gal	MMBTU/hr from Oil
2	819	62	158,104	125
Average	819	62	158,104	125

Permit Maximum on Oil	[mmBtu/hr]	207
Permit Maximum on Bark	[mmBtu/hr]	245

Allowable Particulate Emissions Calculation

Test total BTU Input from Oil for B Scrubber	125	MM BTU/hr.		
Maximum Steam Output from 3 PB	135,000	lb./hr. [1000 BTU Steam]		
Test Operating Rate	94%			
Test Steam Output Rate	126,484	lb./hr. [135,000 x test operating rate]		
Boiler Efficiency on Oil	65%			
Test Steam from Oil	81,452	lb./hr. [total input from oil x Eff. on oil]		
Test Steam from Bark [by difference]	45,032	lb./hr.		
Boiler Efficiency on Bark	55%	Permit Max.		
Test Heat Input from Bark	82	mmBTU/hr. **245**		
Emissions Factor for Bark	0.207	lb. PM/MMBTU	Permit Maximum	
Emissions Factor for Oil	0.086	lb. PM/MMBTU		
Allowable Emissions from Bark	16.9	lb. PM/hr [emissions factor x heat input]	50.6	#3Bark Only
Allowable Emissions from Oil	10.8	lb. PM/hr [emissions factor x heat input]	16.7	#3 Oil Only
Total Allowable Emissions for B Scrubber	27.7	lb. PM/hr.	(Including Oil Emissions)	
Total Allowable Emissions for B Scrubber	27.7	lb. PM/hr.	(By Oil Emissions Factor or Permit)	
Actual emissions for B Scrubber 8-Jul-05 Test	0.0	lb. PM/hr.		

"B" SCRUBBER STACK TEST ANALYSIS for 8-Jul-05

Steam Output from No. 3 Power Boiler

Run Number	Steam Production [1000 lb./hr. of 1000 BTU/lb. Steam] Power Boiler No. 3
1	124
Average	124
Capacity	135

B Scrubber Actual Total % of Capacity = 92%

Oil Input to Boiler

Run Number	Power Boiler No. 3 Gal. Oil	Test Min.	BTU/gal	MMBTU/hr from Oil
1	785.4	60	158,104	124
Average	785	60	158,104	124

Permit Maximum on Oil	[mmBtu/hr]	207
Permit Maximum on Bark	[mmBtu/hr]	245

Allowable Particulate Emissions Calculation

Test total BTU Input from Oil for B Scrubber	124	MM BTU/hr.		
Maximum Steam Output from 3 PB	135,000	lb./hr. [1000 BTU Steam]		
Test Operating Rate	92%			
Test Steam Output Rate	124,000	lb./hr. [135,000 x test operating rate]		
Boiler Efficiency on Oil	65%			
Test Steam from Oil	80,714	lb./hr. [total input from oil x Eff. on oil]		
Test Steam from Bark [by difference]	43,286	lb./hr.		
Boiler Efficiency on Bark	55%	Permit Max.		
Test Heat Input from Bark	79	mmBTU/hr. **245**		
Emissions Factor for Bark	0.207	lb. PM/MMBTU	Permit Maximum	
Emissions Factor for Oil	0.086	lb. PM/MMBTU		
Allowable Emissions from Bark	16.3	lb. PM/hr [emissions factor x heat input]	50.6	#3Bark Only
Allowable Emissions from Oil	10.7	lb. PM/hr [emissions factor x heat input]	16.7	#3 Oil Only

Total Allowable Emissions for B Scrubber	27.0	lb. PM/hr.	(Including Oil Emissions)
Total Allowable Emissions for B Scrubber	27.0	lb. PM/hr.	(By Oil Emissions Factor or Permit)
Actual emissions for B Scrubber 8-Jul-05 Test	na	lb. PM/hr.	

Power Boilers Scrubber Test

	Power Boiler Scrubber			"B"			
	Date			08-Jul-05			
	Run #		B #	2	(w/oil)		
	Start of Test		*End of Test*		*Totals*	*Time*	
	hours	min	hours	min	min	*corrected*	
Time	15	09	16	11	62	0.96774	
Boiler No. 3							
Steam Flow Integrator (x 1000)	858.4		989.1		130700	126484	lb/hr
Steam Temperature (° F)	729.8		741.9		735.85		
Drum Pressure (psig.)	521.3		564.9		543.1		
Oil Flow Intergrator (bbl.)	44.6		64.1		19.5	792.581	gal/hr
Steam Flow (lb/hr x 1000)	141.4		112.4		126900		
Oil Flow (gpm)	13		13.2		13.1		
Bark Integrator	278		300.6		22.6	22	wet/tons/hr
Bark to Boiler: Num.(s)	2	And / or	3				
Scrubber "B" pH	6.3		6.1		6.2		

Power Boilers Scrubber Test

Power Boiler Scrubber **"B"**
Date 08-Jul-05
Run # B # 1 (w/oil)

	Start of Test (hours)	(min)	End of Test (hours)	(min)	Totals (min)	Time corrected	
Time	13	58	14	58	60	1	
Boiler No. 3							
Steam Flow Integrator (x 1000)	712.3		836.3		124000	124000	lb/hr
Steam Temperature (° F)	746.1		740.7		743.4		
Drum Pressure (psig.)	562.7		545.6		554.15		
Oil Flow Intergrator (bbl.)	22.7		41.4		18.7	785.4	gal/hr
Steam Flow (lb/hr x 1000)	109.8		124.8		117300		
Oil Flow (gpm)	13.4		13.5		13.45		
Bark Integrator	251.5		274.2		22.7	23	wet/tons/hr
Bark to Boiler:	Num.(s)	2	And / or	3			
Scrubber "B" pH	7.3		6.4		6.9		

"B" SCRUBBER STACK TEST ANALYSIS for 8-Jul-05

Steam Output from No. 3 Power Boiler

Run Number	Steam Production [1000 lb./hr. of 1000 BTU/lb. Steam] Power Boiler No. 3
1	104
2	100
3	103
Average	102
Capacity	135

B Scrubber Actual Total % of Capacity = 76%

Oil Input to Boiler

	Power Boiler No. 3				
Run Number	Gal. Oil	Test Min.	BTU/gal	MMBTU/hr from Oil	Test Result per Stack test
1	0	60	158,104	0	na
2	4.2	60	158,104	1	na
3	29.4	61	158,104	5	na
Average	11	60	158,104	2	na
Permit Maximum	[mmBtu/hr]			207	

Allowable Particulate Emissions Calculation

Test total BTU Input from Oil for B Scrubber	2	MM BTU/hr.	
Maximum Steam Output from 3 PB	135,000	lb./hr. [1000 BTU Steam]	
Test Operating Rate	76%		
Test Steam Output Rate	102,292	lb./hr. [135,000 x test operating rate]	
Boiler Efficiency on Oil	65%		
Test Steam from Oil	1,134	lb./hr. [total input from oil x Eff. on oil]	
Test Steam from Bark [by difference]	101,158	lb./hr.	
Boiler Efficiency on Bark	55%	Permit Max.	
Test Heat Input from Bark	184	mmBTU/hr 245	
Emissions Factor for Bark	0.207	lb. PM/MMBTU	Permit Maximum
Emissions Factor for Oil	0.086	lb. PM/MMBTU	
Allowable Emissions from Bark	38.1	lb. PM/hr [emissions factor x heat input]	50.6
Allowable Emissions from Oil	0.2	lb. PM/hr [emissions factor x heat input]	16.7
Total Allowable Emissions for B Scrubber	38.2	lb. PM/hr.	(Including Oil Emissions)
Total Allowable Emissions for B Scrubber	38.2	lb. PM/hr.	(By Oil Emissions Factor or Permit)
Actual emissions for B Scrubber 8-Jul-05 Test	na	lb. PM/hr.	

"B" SCRUBBER STACK TEST ANALYSIS for 8-Jul-05

Steam Output from No. 3 Power Boiler

Run Number	Steam Production [1000 lb./hr. of 1000 BTU/lb. Steam] Power Boiler No. 3
3	103
Average	103
Capacity	135

B Scrubber Actual Total % of Capacity = 77%

Oil Input to Boiler

	Power Boiler No. 3			
Run Number	Gal. Oil	Test Min.	BTU/gal	MMBTU/hr from Oil
3	29	61	158,104	5
Average	29	61	158,104	5

Permit Maximum on Oil	[mmBtu/hr]	207
Permit Maximum on Bark	[mmBtu/hr]	245

Allowable Particulate Emissions Calculation

Test total BTU Input from Oil for B Scrubber	5	MM BTU/hr.		
Maximum Steam Output from 3 PB	135,000	lb./hr. [1000 BTU Steam]		
Test Operating Rate	77%			
Test Steam Output Rate	103,377	lb./hr. [135,000 x test operating rate]		
Boiler Efficiency on Oil	65%			
Test Steam from Oil	2,972	lb./hr. [total input from oil x Eff. on oil]		
Test Steam from Bark [by difference]	100,405	lb./hr.		
Boiler Efficiency on Bark	55%	Permit Max.		
Test Heat Input from Bark	183	mmBTU/hr. **245**		
Emissions Factor for Bark	0.207	lb. PM/MMBTU	Permit Maximum	
Emissions Factor for Oil	0.086	lb. PM/MMBTU		
Allowable Emissions from Bark	37.8	lb. PM/hr [emissions factor x heat input]	50.6	#3Bark Only
Allowable Emissions from Oil	0.4	lb. PM/hr [emissions factor x heat input]	16.7	#3 Oil Only

Total Allowable Emissions for B Scrubber	38.2	lb. PM/hr.	(Including Oil Emissions)
Total Allowable Emissions for B Scrubber	38.2	lb. PM/hr.	(By Oil Emissions Factor or Permit)
Actual emissions for B Scrubber 8-Jul-05 Test	na	lb. PM/hr.	

"B" SCRUBBER STACK TEST ANALYSIS for 8-Jul-05

Steam Output from No. 3 Power Boiler

Run Number	Steam Production [1000 lb./hr. of 1000 BTU/lb. Steam] Power Boiler No. 3
2	100
Average	100
Capacity	135

B Scrubber Actual Total % of Capacity = 74%

Oil Input to Boiler

	Power Boiler No. 3			
Run Number	Gal. Oil	Test Min.	BTU/gal	MMBTU/hr from Oil
2	4.2	60	158,104	1
Average	4	60	158,104	1

Permit Maximum on Oil	[mmBtu/hr]	207
Permit Maximum on Bark	[mmBtu/hr]	245

Allowable Particulate Emissions Calculation

Test total BTU Input from Oil for B Scrubber	1	MM BTU/hr.		
Maximum Steam Output from 3 PB	135,000	lb./hr. [1000 BTU Steam]		
Test Operating Rate	74%			
Test Steam Output Rate	100,000	lb./hr. [135,000 x test operating rate]		
Boiler Efficiency on Oil	65%			
Test Steam from Oil	432	lb./hr. [total input from oil x Eff. on oil]		
Test Steam from Bark [by difference]	99,568	lb./hr.		
Boiler Efficiency on Bark	55%	Permit Max.		
Test Heat Input from Bark	181	mmBTU/hr. **245**		
Emissions Factor for Bark	0.207	lb. PM/MMBTU	Permit Maximum	
Emissions Factor for Oil	0.086	lb. PM/MMBTU		
Allowable Emissions from Bark	37.5	lb. PM/hr [emissions factor x heat input]	50.6	#3Bark Only
Allowable Emissions from Oil	0.1	lb. PM/hr [emissions factor x heat input]	16.7	#3 Oil Only
Total Allowable Emissions for B Scrubber	37.5	lb. PM/hr.	(Including Oil Emissions)	
Total Allowable Emissions for B Scrubber	37.5	lb. PM/hr.	(By Oil Emissions Factor or Permit)	
Actual emissions for B Scrubber 8-Jul-05 Test	na	lb. PM/hr.		

"B" SCRUBBER STACK TEST ANALYSIS for 8-Jul-05

Steam Output from No. 3 Power Boiler

Run Number	Steam Production [1000 lb./hr. of 1000 BTU/lb. Steam] Power Boiler No. 3
1	104
Average	104
Capacity	135

B Scrubber Actual Total % of Capacity = 77%

Oil Input to Boiler

	Power Boiler No. 3			
Run Number	Gal. Oil	Test Min.	BTU/gal	MMBTU/hr from Oil
1	0	60	158,104	0
Average	0	60	158,104	0

Permit Maximum on Oil	[mmBtu/hr]	207
Permit Maximum on Bark	[mmBtu/hr]	245

Allowable Particulate Emissions Calculation

Test total BTU Input from Oil for B Scrubber	0	MM BTU/hr.		
Maximum Steam Output from 3 PB	135,000	lb./hr. [1000 BTU Steam]		
Test Operating Rate	77%			
Test Steam Output Rate	103,500	lb./hr. [135,000 x test operating rate]		
Boiler Efficiency on Oil	65%			
Test Steam from Oil	0	lb./hr. [total input from oil x Eff. on oil]		
Test Steam from Bark [by difference]	103,500	lb./hr.		
Boiler Efficiency on Bark	55%	Permit Max.		
Test Heat Input from Bark	188	mmBTU/hr. **245**		
Emissions Factor for Bark	0.207	lb. PM/MMBTU	Permit Maximum	
Emissions Factor for Oil	0.086	lb. PM/MMBTU		
Allowable Emissions from Bark	50.6	lb. PM/hr [emissions factor x heat input]	50.6	#3Bark Only
Allowable Emissions from Oil	0.0	lb. PM/hr [emissions factor x heat input]	16.7	#3 Oil Only
Total Allowable Emissions for B Scrubber	50.6	lb. PM/hr.	(Including Oil Emissions)	
Total Allowable Emissions for B Scrubber	50.6	lb. PM/hr.	(By Oil Emissions Factor or Permit)	
Actual emissions for B Scrubber 8-Jul-05 Test	na	lb. PM/hr.		

Power Boilers Scrubber Test

Power Boiler Scrubber "B"

Date 08-Jul-05

Run # B # 3 (no/oil)

	Start of Test		End of Test		Totals	Time corrected	
	hours	min	hours	min	min		
Time	11	38	12	39	61	0.98361	
Boiler No. 3							
Steam Flow Integrator (x 1000)	469.1		574.2		105100	103377	lb/hr
Steam Temperature (° F)___	774.2		766.9		770.55		
Drum Pressure (psig.)_____	555.1		546.9		551		
Oil Flow Intergrator (bbl.)__	6.8		7.5		0.7	28.918	gal/hr
*Steam Flow (lb/hr x 1000)_*	106		98.7		102350		
Oil Flow (gpm)_________	0		0		0		
Bark Integrator	180.5		215.3		34.8	34	wet/tons/hr
Bark to Boiler: Num.(s)		2		3			
Scrubber "B" pH	8.0		8.1		8.05		

Power Boilers Scrubber Test

Power Boiler Scrubber **"B"**
Date 08-Jul-05
Run # B # 2 (no/oil)

	Start of Test		End of Test		Totals	Time corrected	
	hours	min	hours	min	min		
Time	10	23	11	23	60	1	
Boiler No. 3							
Steam Flow Integrator (x 1000)	348.2		448.2		100000	100000	lb/hr
Steam Temperature (° F)	784.6		734.1		759.35		
Drum Pressure (psig.)	550.8		458.2		504.5		
Oil Flow Intergrator (bbl.)	4.6		4.7		0.1	4.2	gal/hr
Steam Flow (lb/hr x 1000)	104		55.6		79800		
Oil Flow (gpm)	0		0		0		
Bark Integrator	133.6		170.1		36.5	37	wet/tons/hr
Bark to Boiler:	Num.(s)	2	And / or	3			
Scrubber "B" pH	8.1		8.3		8.2		

Power Boilers Scrubber Test

Power Boiler Scrubber **"B"**
Date 08-Jul-05
Run # B # 1 (no/oil)

	Start of Test hours	min	End of Test hours	min	Totals min	Time corrected	
Time	9	00	10	00	60	1	
Boiler No. 3							
Steam Flow Integrator (x 1000)	206		309.5		103500	103500	lb/hr
Steam Temperature (° F)	778.5		748.1		763.3		
Drum Pressure (psig.)	532.7		520.8		526.75		
Oil Flow Intergrator (bbl.)	4.6		4.6		0	0	gal/hr
Steam Flow (lb/hr x 1000)	106.9		114.1		110500		
Oil Flow (gpm)	0		0		0		
Bark Integrator	85.5		118.7		33.2	33	wet/tons/hr
Bark to Boiler: Num.(s)	2	And / or	3				
Scrubber "B" pH	8.1		8.1		8.1		

	Test Value	21.9	PM lb/hr
	Test Value	0.80	PM lb/ADTUP
	Permit Limit	2.5	PM lb/ADTUP
		64,042	lb SSLS/hr
Entry from		27	ADTUP/hr
previous operating years Data	lb SSLS/ADTUP	2,330	

Sulfite Recovery Boiler Scrubber Stack Test Analysis

for 8-Jun-05

Steam Output from the Sulfite Recovery Boiler

Run Number	Steam Production [1000 lb./hr. of 1000 BTU/lb. Steam] Sulfite Recovery Boiler
1	374
2	309
3	353
Average	345

Oil Input to Boiler — **Liquor Input to Boiler** — **Test Result**

Run Number	Gal. Oil	Test Min.	BTU/gal	MMBTU/hr from Oil	Gal. Liquor	Liquor Flow lbs/hr.	Particulate (per Stack test) lbs/hr.
	Sulfite Recovery Boiler						
1	0	60	158,104	0	10493	64,110	12.4
2	0	65	158,104	0	8510	66,662	28.7
3	0	61	158,104	0	9748	61,355	24.5
Average	0	62	158,104	0	9,584	64,042	21.9

Permit Maximum	[lbs/hr. SSL]	70,000
Recovery Boiler Actual Total % of Capacity =		91%
Standard Operating Max		63,000
Percent of Standard Operating Max		102%

Permit Maximum	(particulate)	43.18 lbs/hr.
Permit Maximum	(particulate)	43.18 lbs/hr.
Permit Limit	**2.5**	PM lb/ADTUP
Test Value	**0.80**	PM lb/ADTUP

Recovery Boiler Compliance Test

Date: 8-Jun-05

Run: # 3

	Start of Test hour	min	End of Test hour	min	Difference	%of hour	
Time	12	48	13	49	61	0.983607	
"B" Liquor Flow, gallons	65760.8		75671		9910.2	9747.738	gph
Liquor Flow, gpm meter	175		172		173.5	10410	gph
Liquor Temperature, deg F	194		194		194		
Liquor Hydrometer Reading	1.255		1.255		1.255		
Liquor solids, % OD	60.1		60.1		60.1		
No. of Liquor guns	10		10		10		
No. of oil guns	0		0		0		
No. of oil guns @ pressure	0		0		0		
Steam load, lbs/hr chart x 1000	376		373		374.5		
Steam Flow Integrator x 1000, lb	2376.2		2734.6		358400	352524.6	lb/hr
Steam Temperature, deg F	873		869		871		
Steam Pressure, psi	987		987		987		
SO2, ppm	22.804		23.672		23.238		

Liquor Flow Calculation	(gph)(8.345)(sp.gr.)(%OD)	61354.78 lb/hr

Integrator Calculation: TSP Mass Emission Rate results: 24.48 lb/hr

(End of test value - Start of test value)(60 min./hr / Test time, min.) = Units/hr

Recovery Boiler Compliance Test

Date: 8-Jun-05

Run: # 2

	Start of Test hour	min	End of Test hour	min	Difference	%of hour	
Time	11	06	12	11	65	0.923077	
"B" Liquor Flow, gallons	49546.6		58766		9219.4	8510.215	gph
Liquor Flow, gpm meter	175		175		175	10500	gph
Liquor Temperature, deg F	194		194		194		
Liquor Hydrometer Reading	1.26		1.255		1.2575		
Liquor solids, % OD	60.9		60.1		60.5		
No. of Liquor guns	10		10		10		
No. of oil guns	0		0		0		
No. of oil guns @ pressure	0		0		0		
Steam load, lbs/hr chart x 1000	379		378		378.5		
Steam Flow Integrator x 1000, lb	1787.3		2122.1		334800	309046.2	lb/hr
Steam Temperature, deg F	876		876		876		
Steam Pressure, psi	993		996		994.5		
SO2, ppm	117.874		113.084		115.479		

Liquor Flow Calculation	(gph)(8.345)(sp.gr.)(%OD)	66662.10	lb/hr

Integrator Calculation: TSP Mass Emission Rate results: 28.72 lb/hr

(End of test value - Start of test value)(60 min./hr / Test time, min.) = Units/hr

Recovery Boiler Compliance Test

Date: 8-Jun-05

Run: # 1

	Start of Test hour	min	End of Test hour	min	Difference	%of hour	
Time	9	02	10	02	60	1	
"B" Liquor Flow, gallons	25747.5		36240.6		10493.1	10493.1	gph
Liquor Flow, gpm meter	176		174		175	10500	gph
Liquor Temperature, deg F	193		194		193.5		
Liquor Hydrometer Reading	1.25		1.245		1.2475		
Liquor solids, % OD	59		58.3		58.65		
No. of Liquor guns	10		10		10		
No. of oil guns	0		0		0		
No. of oil guns @ pressure	0		0		0		
Steam load, lbs/hr chart x 1000	372		376		374		
Steam Flow Integrator x 1000, lb	935.5		1309.7		374200	374200	lb/hr
Steam Temperature, deg F	875		876		875.5		
Steam Pressure, psi	992		993		992.5		
SO2, ppm	147.969		242.566		195.2675		

Liquor Flow Calculation	(gph)(8.345)(sp.gr.)(%OD)	64109.77	lb/hr
Integrator Calculation:	TSP Mass Emission Rate results:	12.37	lb/hr

(End of test value - Start of test value)(60 min./hr / Test time, min.) = Units/hr

Dick Hopper/RayFB/Rayonier

10/26/2005 07:57 AM

To Tricia.Harrell@rayonier.com
cc
bcc
Subject Fw: Sept 28 Community Environmental Advisory Committee Mtg.

Don't you provide an agenda for the attendees? Please see Dave & Jack for their slides. Jack and CA will need to look at the #6 PB slides I have well before Friday.

Thanks,

Dick

Richard W. [Dick] Hopper
Manager, Environmental Operations
Rayonier Fernandina Mill
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Fernandina Beach, FL 32035
(904) 277-1480
dick.hopper@rayonier.com
----- Forwarded by Dick Hopper/RayFB/Rayonier on 10/26/2005 07:56 AM -----

David Tudor/RayFB/Rayonier

10/25/2005 03:36 PM

To jack.perrett@rayonier.com, dick.hopper@rayonier.com
cc
Subject Sept 28 Community Environmental Advisory Committee Mtg.

Jack and Dick,
Here is a very preliminary agenda with some ideas of presentations
Dave

Welcome and Introductions — Tudor

Recent Environmental/Safety Compliance History — Hopper

Mill Business Status Recent Business Developments — Perrett
Market changes: Nachez, Cosmopolis, Brazil, So Africa. & market share

Consumptive Use Permit — Tudor
allocation, usage, well field management, conservation projects,
coop with Smurfit on Aquifer Stress Test
Bill Crews on Smurfit Permit

Title V Permit — Tudor
status, CAM plan monitoring

No. 6 boiler Permit Application — Hopper
equipment changes needed for production increase
local impacts due to production increase.
location & configuration & control equipment
fuel and emissions comparison to existing

Lunch

Environmental Advisory Committee Checklist

Meeting Date ~~12/10/04~~ 10/28/05

		Yes	No	
Alley, Gene	277-3433		X	
Caples, David	261-1137		X	Kelli
Colburn, Elle 1541 Inverness Rd.	261-6945	X		
Dahlgren, Charles	277-2692		X	
Duncan, Regina	261-3248		X	
Duncan, Todd	548-0162	X		
~~Kathy Russell~~	261-5713			
Kinner, Derek	261-7606 ext 106			msg. 277-7334
? Kirkland-Brown, Maybelle	277-3285			
? Leeper, Danny	277-7331	X		
Main, Orrin	277-3576	X		
~~Mearns, Bob~~	~~277-7305~~			
Parnell, Michael	261-3696	~~X~~		cancelled
Rogers, Bob	277-3725	X		
Sabadie, Patrick	261-6639		X	
Scanlan, Phil	491-8852	X		
Smith, Mayo	261-5586		X	
Sparkman, Wade	277-7284	X		
Van Horn, Michael	261-9763		X	
Whitaker, Melba	261-3841	X		* msg.

John Mandrick X

Jack Perrett X

Dave Tudor X

Dick Hopper X

Stephanie Woodward ???

Tricia Harrell X

Mike Bell X

Bill Crews X

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APPENDIX C

PROCESS DATA

NATIONAL SPECIALTY GASES

P. O. Box 12013
Research Triangle Park, N.C. 27709
Phone 919/544-3772

CERTIFICATE OF ANALYSIS: EPA PROTOCOL GAS MIXTURE

Customer:	National Welders, Durham, NC	Reference #	88-91270
NSG PO#	4436836	Certification Date:	06/21/04
Customer PO#		Expiration Date:	06/21/07
Cylinder #	CC47306	Pressure, psig*	2000

ANALYTICAL INFORMATION

METHOD: This standard was analyzed according to EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards: Procedure G1 (September 1997)

ANALYZED CYLINDER

Components	Certified Concentration	Analytical Accuracy**
Oxygen	12.41%	+/-1%
Carbon Dioxide	9.09%	+/-1%
Balance - Nitrogen		

REFERENCE STANDARD

Type/SRM Sample #	Cylinder #	Concentration	
GMIS (Traceable to SRM # 2659a)	CC64388	24.74 %	O2/N2
GMIS (Traceable to SRM # 1674b)	CC52150	9.93 %	CO2/N2

INSTRUMENTATION

Instrument/Model/Serial #		Last Date Calibrated	Analytical Method
Horiba MPA - 510 O2	41499150042	06/09/04	Paramagnetic
Horiba VIA-510 CO2	42399380022	06/04/04	Non-dispersive Infrared

Analyst: Richard Sykes Richard Sykes

This report states accurately the results of the investigation made upon the material submitted to the analytical laboratory. Every effort has been made to determine objectively the information requested. However, in connection with this report, National Specialty Gases shall have no liability in excess of established charge for this service. Assayed at National Specialty Gases, 630 United Drive, Durham, NC 27713 (919) 544-3772

*Do not use this standard when cylinder pressure is below 150 psig.

**Analytical accuracy includes typical known error sources which, at least, include precision of the analytical instrument.

NSG 020149L

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CERTIFICATE OF ANALYSIS: EPA PROTOCOL GAS MIXTURE

Customer:	National Welders, Durham, NC	Reference #	88-91271
NSG PO#	4436836	Certification Date:	06/21/04
Customer PO#		Expiration Date:	06/21/07
Cylinder #	CC35809	Pressure, psig*	2000

ANALYTICAL INFORMATION

METHOD: This standard was analyzed according to EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards: Procedure G1 (September 1997)

ANALYZED CYLINDER

Components	Certified Concentration	Analytical Accuracy**
Oxygen	20.0%	+/-1%
Carbon Dioxide	18.18%	+/-1%
Balance - Nitrogen		

REFERENCE STANDARD

Type/SRM Sample #	Cylinder #	Concentration	
GMIS (Traceable to SRM # 2659a)	CC64388	24.74 %	O2/N2
GMIS (Traceable to SRM # 1675b)	CC146489	20.22 %	CO2/N2

INSTRUMENTATION

Instrument/Model/Serial #		Last Date Calibrated	Analytical Method
Horiba MPA - 510 O2	41499150042	06/09/04	Paramagnetic
Horiba VIA-510 CO2	42399380022	06/04/04	Non-dispersive Infrared

Analyst: Richard Sykes Richard Sykes

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CERTIFICATE OF ANALYSIS: EPA PROTOCOL GAS MIXTURE

Customer:	National Welders, Durham, NC	Reference #	88-96748
NSG PO#	4850658	Certification Date:	04/05/05
Customer PO#		Expiration Date:	04/05/08
Cylinder #	CC62939	Pressure, psig*	2000

ANALYTICAL INFORMATION

METHOD: This standard was analyzed according to EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards: Procedure G1 (September 1997)

ANALYZED CYLINDER Components	Certified Concentration	Analytical Accuracy**
Oxygen	20.0 %	+/-1%
Balance - Nitrogen		

REFERENCE STANDARD Type/SRM Sample #	Cylinder #	Concentration	
GMIS (Traceable to SRM # 2659a)	CC66774	24.77 %	O2/N2

INSTRUMENTATION Instrument/Model/Serial #	Last Date Calibrated	Analytical Method
Horiba MPA - 510 O2 41499150042	03/17/05	Paramagnetic

Analyst: Nicole Ishak — Nicole Ishak

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CERTIFICATE OF ANALYSIS: EPA PROTOCOL GAS MIXTURE

Customer:	National Welders, Raleigh, NC	Reference #	88-87924
NSG PO#	4179631	Certification Date:	12/09/03
Customer PO#		Expiration Date:	12/09/05
Cylinder #	CC47297	Pressure, psig*	2000

ANALYTICAL INFORMATION

METHOD: This standard was analyzed according to EPA Traceability Protocol for Assay and certification of Gaseous Calibration Standards: Procedure G-1: September 1997.

ANALYZED CYLINDER

Components	Certified Concentration	Analytical Accuracy**
Nitric Oxide	44.4 ppm	+/-1%
Carbon Monoxide	45.6 ppm	+/-1%

Balance - Nitrogen   Trace Gas - Nitrogen Dioxide   < 0.1 ppm

REFERENCE STANDARD

Type/SRM Sample #	Cylinder #	Concentration	
GMIS (Traceable to SRM # 1683b)	CC67255	49.53 ppm	NO/N2
GMIS (Traceable to SRM # 1678c)	CC41286	50.64 ppm	CO/N2

INSTRUMENTATION

Instrument/Model/Serial #		Last Date Calibrated	Analytical Method
TECO 42CHL NOX	CHL-63965-341	11/14/03	Chemiluminescence
Rosemount 880A CO	00172	11/21/03	Non-dispersive Infrared

Analyst: Jeremy Kenworthy

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CERTIFICATE OF ANALYSIS: EPA PROTOCOL GAS MIXTURE

Customer:	National Welders, Durham, NC	Reference #	88-90594
NSG PO#	4377631	Certification Date:	05/10/04
Customer PO#		Expiration Date:	05/10/06
Cylinder #	CC114333	Pressure, psig*	2000

ANALYTICAL INFORMATION

METHOD: This standard was analyzed according to EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards: Procedure G1 (September 1997)

ANALYZED CYLINDER

Components	Certified Concentration	Analytical Accuracy**
Carbon Monoxide	96.8 ppm	+/-1%
Nitric Oxide	94.4 ppm	+/-1%

Balance - Nitrogen Trace Gas - Nitrogen Dioxide < 0.1 ppm

REFERENCE STANDARD

Type/SRM Sample #	Cylinder #	Concentration	
GMIS (Traceable to SRM # 1679c)	CC64442	98.3 ppm	CO/N2
GMIS (Traceable to SRM # 1684b)	CC64261	99.85 ppm	NO/N2

INSTRUMENTATION

Instrument/Model/Serial #		Last Date Calibrated	Analytical Method
Rosemount 880A CO	00172	04/22/04	Non-dispersive Infrared
KVB Analect	EN-844	05/03/04	Fourier Transform Infrared

Analyst: J Kenworthy Jeremy Kenworthy

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CERTIFICATE OF ANALYSIS: EPA PROTOCOL GAS MIXTURE

Customer:	National Welders, Durham, NC	Reference #	88-93853
NSG PO#	4614344	Certification Date:	10/25/04
Customer PO#		Expiration Date:	10/25/06
Cylinder #	CC44386	Pressure, psig*	2000

ANALYTICAL INFORMATION

METHOD: This standard was analyzed according to EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards: Procedure G1 (September 1997)

ANALYZED CYLINDER

Components	Certified Concentration	Analytical Accuracy**
Nitric Oxide	44.5 ppm	+/-1%
Carbon Monoxide	48.3 ppm	+/-1%

Balance - Nitrogen   Trace Gas - Nitrogen Dioxide   < 0.1 ppm

REFERENCE STANDARD

Type/SRM Sample #	Cylinder #	Concentration	
GMIS (Traceable to SRM # 1683b)	CC50340	50.1 ppm	NO/N2
GMIS (Traceable to SRM # 1678c)	CC41286	50.64 ppm	CO/N2

INSTRUMENTATION

Instrument/Model/Serial #		Last Date Calibrated	Analytical Method
KVB Analect	EN-844	10/01/04	Fourier Transform Infrared
Rosemount 880A CO	00172	10/05/04	Non-dispersive Infrared

Analyst: [signature] Jeremy Kenworthy

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CERTIFICATE OF ANALYSIS: EPA PROTOCOL GAS MIXTURE

Customer:	National Welders, Durham, NC	Reference #	88-91270
NSG PO#	4436836	Certification Date:	06/21/04
Customer PO#		Expiration Date:	06/21/07
Cylinder #	CC41520	Pressure, psig*	2000

ANALYTICAL INFORMATION

METHOD: This standard was analyzed according to EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards: Procedure G1 (September 1997)

ANALYZED CYLINDER

Components	Certified Concentration	Analytical Accuracy**
Oxygen	12.41%	+/-1%
Carbon Dioxide	9.09%	+/-1%
Balance - Nitrogen		

REFERENCE STANDARD

Type/SRM Sample #	Cylinder #	Concentration	
GMIS (Traceable to SRM # 2659a)	CC64388	24.74 %	O2/N2
GMIS (Traceable to SRM # 1674b)	CC52150	9.93 %	CO2/N2

INSTRUMENTATION

Instrument/Model/Serial #		Last Date Calibrated	Analytical Method
Horiba MPA - 510 O2	41499150042	06/09/04	Paramagnetic
Horiba VIA-510 CO2	42399380022	06/04/04	Non-dispersive Infrared

Analyst: Richard Sykes Richard Sykes

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CERTIFICATE OF ANALYSIS: EPA PROTOCOL GAS MIXTURE

Customer:	National Welders, Raleigh, NC	Reference #	88-87982
NSG PO#	4179631	Certification Date:	12/12/03
Customer PO#		Expiration Date:	12/12/05
Cylinder #	SG9163408BAL	Pressure, psig*	2000

ANALYTICAL INFORMATION

METHOD: This standard was analyzed according to EPA Traceability Protocol for Assay and certification of Gaseous Calibration Standards: *Procedure G-1: September 1997.*

ANALYZED CYLINDER

Components	Certified Concentration	Analytical Accuracy**
Nitric Oxide	454 ppm	+/-1%
Carbon Monoxide	619 ppm	+/-1%

Balance - Nitrogen   Trace Gas - Nitrogen Dioxide   < 1.0 ppm

REFERENCE STANDARD

Type/SRM Sample #	Cylinder #	Concentration	
GMIS (Traceable to SRM # 1686b)	CC16989	502.6 ppm	NO/N2
GMIS (Traceable to SRM # 1680b)	CC47351	497.7 ppm	CO/N2

INSTRUMENTATION

Instrument/Model/Serial #		Last Date Calibrated	Analytical Method
KVB Analect	EN-844	12/01/03	Fourier Transform Infrared
Rosemount 880A CO	00172	11/21/03	Non-dispersive Infrared

Analyst: J Kenworthy   Jeremy Kenworthy

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CERTIFICATE OF ANALYSIS: EPA PROTOCOL GAS MIXTURE

Customer:	National Welders, Raleigh, NC	Reference #	88-88043
NSG PO#	4179631	Certification Date:	12/19/03
Customer PO#		Expiration Date:	12/19/05
Cylinder #	CC51105	Pressure, psig*	2000

ANALYTICAL INFORMATION

METHOD: This standard was analyzed according to EPA Traceability Protocol for Assay and certification of Gaseous Calibration Standards: Procedure G-1: September 1997.

ANALYZED CYLINDER

Components	Certified Concentration	Analytical Accuracy**
Nitric Oxide	178.9 ppm	+/-1%
Carbon Monoxide	306 ppm	+/-1%

Balance - Nitrogen Trace Gas - Nitrogen Dioxide 0.2 ppm

REFERENCE STANDARD

Type/SRM Sample #	Cylinder #	Concentration	
GMIS (Traceable to SRM # 1685b)	CC109646	205.2 ppm	NO/N2
GMIS (Traceable to SRM # 2636a)	CC104276	251.5 ppm	CO/N2

INSTRUMENTATION

Instrument/Model/Serial #		Last Date Calibrated	Analytical Method
KVB Analect	EN-844	12/01/03	Fourier Transform Infrared
Rosemount 880A CO	00172	11/21/03	Non-dispersive Infrared

Analyst: Jeremy Kenworthy

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CERTIFICATE OF ANALYSIS: EPA PROTOCOL GAS MIXTURE

Customer:	National Welders, Raleigh, NC	Reference #	88-87977
NSG PO#	4179631	Certification Date:	12/15/03
Customer PO#		Expiration Date:	12/15/05
Cylinder #	CC36113	Pressure, psig*	2000

ANALYTICAL INFORMATION

METHOD: This standard was analyzed according to EPA Traceability Protocol for Assay and certification of Gaseous Calibration Standards: Procedure G-1: September 1997.

ANALYZED CYLINDER

Components	Certified Concentration	Analytical Accuracy**
Nitric Oxide	908 ppm	+/-1%
Carbon Monoxide	905 ppm	+/-1%

Balance - Nitrogen   Trace Gas - Nitrogen Dioxide   < 1.0 ppm

REFERENCE STANDARD

Type/SRM Sample #	Cylinder #	Concentration	
GMIS (Traceable to SRM # 1687b)	CC129690	997 ppm	NO/N2
GMIS (Traceable to SRM # 1681b)	CC21531	975.8 ppm	CO/N2

INSTRUMENTATION

Instrument/Model/Serial #		Last Date Calibrated	Analytical Method
KVB Analect	EN-844	12/01/03	Fourier Transform Infrared
Rosemount 880A CO	00172	11/21/03	Non-dispersive Infrared

Analyst: J Kenworthy   Jeremy Kenworthy

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NSG 020149L

CERTIFICATE OF ANALYSIS: EPA PROTOCOL GAS MIXTURE

Customer:	National Welders, Durham, NC	Reference #	88-91339
NSG PO#	4436836	Certification Date:	06/24/04
Customer PO#		Expiration Date:	06/24/06
Cylinder #	CC47341	Pressure, psig*	2000

ANALYTICAL INFORMATION

METHOD: This standard was analyzed according to EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards: Procedure G1 (September 1997)

ANALYZED CYLINDER

Components	Certified Concentration	Analytical Accuracy**
Carbon Monoxide	47.9 ppm	+/-1%
Nitric Oxide	47.0 ppm	+/-1%

Balance - Nitrogen   Trace Gas - Nitrogen Dioxide   1.2 ppm

REFERENCE STANDARD

Type/SRM Sample #	Cylinder #	Concentration	
GMIS (Traceable to SRM # 1678c)	CC41286	50.64 ppm	CO/N2
GMIS (Traceable to SRM # 1683b)	CC59951	48.74 ppm	NO/N2

INSTRUMENTATION

Instrument/Model/Serial #		Last Date Calibrated	Analytical Method
Rosemount 880A CO	00172	05/25/04	Non-dispersive Infrared
TECO 42CHL NOX	CHL-63965-341	05/19/04	Chemiluminescence

Analyst: ______________ Richard Sykes

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CERTIFICATE OF ANALYSIS: EPA PROTOCOL GAS MIXTURE

Customer:	National Welders, Durham, NC	Reference #	88-93852
NSG PO#	4614344	Certification Date:	10/25/04
Customer PO#		Expiration Date:	10/25/06
Cylinder #	XC033413B	Pressure, psig*	2000

ANALYTICAL INFORMATION

METHOD: This standard was analyzed according to EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards: Procedure G1 (September 1997)

ANALYZED CYLINDER

Components	Certified Concentration	Analytical Accuracy**
Nitric Oxide	92.9 ppm	+/-1%
Carbon Monoxide	96.0 ppm	+/-1%

Balance - Nitrogen   Trace Gas - Nitrogen Dioxide   < 0.1 ppm

REFERENCE STANDARD

Type/SRM Sample #	Cylinder #	Concentration	
GMIS (Traceable to SRM # 1684b)	CC103603	100.5 ppm	NO/N2
GMIS (Traceable to SRM # 1679c)	CC181905	98.5 ppm	CO/N2

INSTRUMENTATION

Instrument/Model/Serial #		Last Date Calibrated	Analytical Method
KVB Analect	EN-844	10/01/04	Fourier Transform Infrared
Rosemount 880A CO	00172	10/05/04	Non-dispersive Infrared

Analyst: ______________ Jeremy Kenworthy

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CERTIFICATE OF ANALYSIS: EPA PROTOCOL GAS MIXTURE

Customer:	National Welders, Durham, NC	Reference #	88-96915
NSG PO#	4850658	Certification Date:	04/14/05
Customer PO#		Expiration Date:	04/14/08
Cylinder #	CC47767	Pressure, psig*	2000

ANALYTICAL INFORMATION

METHOD: This standard was analyzed according to EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards: Procedure G1 (September 1997)

ANALYZED CYLINDER

Components	Certified Concentration	Analytical Accuracy**
Oxygen	12.53%	+/-1%
Balance - Nitrogen		

REFERENCE STANDARD

Type/SRM Sample #	Cylinder #	Concentration	
GMIS (Traceable to SRM # 2659a)	CC46336	20.03 %	O2/N2

INSTRUMENTATION

Instrument/Model/Serial #	Last Date Calibrated	Analytical Method
Horiba MPA - 510 O2 41499150042	03/17/05	Paramagnetic

Analyst: B P Moore Brian P. Moore

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RAYONIER
SULFITE RECOVERY BOILER
SO2 RELATIVE ACCURACY TEST AUDIT
O2 Nox Bias/Drift Correction Calculation Spreadsheet

Nox RUN #		**1**	**2**	**3**
	Start	**9:00**	**10:54**	**12:53**
	End	**10:41**	**12:21**	**14:31**
REFERENCE METHOD BIAS ADJUSTED VALUES	**PRELIM**			
O2(%V,dry)	#N/A	4.5	4.1	4.9
NOX(ppmV,dry)	#N/A	590.3	576.2	637.3
SO2(ppmV,dry)	#N/A	216.5	119.8	53.0
RAW AVERAGES	**PRELIM**			
O2(%V,dry)	#N/A	4.7	4.3	5.0
NOX(ppmV,dry)	#N/A	590.2	576.8	639.7
SO2(ppmV,dry)	#N/A	218.4	119.8	52.4
ZERO BIAS	**PRELIM**			
O2(%V,dry)	0.2	0.2	0.2	0.2
NOX(ppmV,dry)	1.1	2.3	1.0	3.1
SO2(ppmV,dry)	1.1	0.5	-2.0	0.2
BIAS CHECKS	**PRELIM**			
O2(%V,dry)	12.6	12.6	12.5	12.5
NOX(ppmV,dry)	911.0	903.0	913.0	908.0
SO2(ppmV,dry)	455.0	455.0	453.0	454.0
BIAS VALUES	**PRELIM**			
O2(%V,dry)	12.5	12.5	12.5	12.5
NOX(ppmV,dry)	908.0	908.0	908.0	908.0
SO2(ppmV,dry)	452.0	452.0	452.0	452.0
Zero Drift/Bias (% of scale)	**SCALE**			
O2(%V,dry)	25	0.00%	0.00%	0.00%
NOX(ppmV,dry)	1000	0.12%	-0.13%	0.21%
SO2(ppmV,dry)	500	-0.12%	-0.50%	0.44%
Upscale Drift/Bias (% of scale)	**SCALE**			
O2(%V,dry)	25	0.00%	-0.40%	0.00%
NOX(ppmV,dry)	1000	-0.80%	1.00%	-0.50%
SO2(ppmV,dry)	500	0.00%	-0.40%	0.20%

Reference: Source Testing And Consulting Services, Inc - JUNE 2005
Each Nox run equivalent to the average of three RA runs.

SCRUBBER B
No. 3 Boiler
RAYONIER
Bias/Drift Correction Calculation Spreadsheet

	Scrubber B			
	BARK & OIL			
	Date	7/14/05	7/14/05	7/14/05
	Start	9:00	10:18	11:37
	Stop	10:00	11:18	12:38
REFERENCE METHOD BIAS ADJUSTED VALUES	**PRELIM**	**1**	**2**	**3**
O2 (%V,dry)	#N/A	12.6	13.2	12.4
NOX (ppmV,dry)	#N/A	73.2	69.8	72.0
CO (ppmV,dry)	#N/A	41.2	39.7	50.9
RAW AVERAGES	**PRELIM**	**1**	**2**	**3**
O2 (%V,dry)	#N/A	12.63	13.21	12.38
NOX (ppmV,dry)	#N/A	73.9	70.5	72.4
CO(ppmvw)	#N/A	41.7	40.1	51.5
ZERO BIAS	**PRELIM**	**1**	**2**	**3**
O2 (%V,dry)	0.01	0.05	0.07	0.06
NOX (ppmV,dry)	0.3	1.0	0.5	0.3
CO(ppmvw)	0.5	0.43	0.5	0.8
BIAS CHECKS	**PRELIM**	**1**	**2**	**3**
O2 (%V,dry)	12.53	12.53	12.58	12.53
NOX (ppmV,dry)	93.2	93.4	93.2	93.1
CO(ppmvw)	97.2	96.4	94.8	96.7
BIAS VALUES	**PRELIM**	**1**	**2**	**3**
O2 (%V,dry)	12.53	12.53	12.53	12.53
NOX (ppmV,dry)	92.9	92.9	92.9	92.9
CO(ppmvw)	96.0	96.0	96.0	96.0
ZERO Drift/Bias (% of scale)	**SCALE**	**1**	**2**	**3**
O2 (%V,dry)	25	0.16%	0.08%	-0.04%
NOX (ppmV,dry)	100	0.69%	-0.55%	-0.12%
CO(ppmvw)	100	-0.06%	0.02%	0.36%
UPSCALE Drift/Bias (% of scale)	**SCALE**	**1**	**2**	**3**
O2 (%V,dry)	25	0.00%	0.20%	-0.20%
NOX (ppmV,dry)	100	0.20%	-0.20%	-0.10%
CO(ppmvw)	100	-0.80%	-1.60%	1.90%

Reference: Source Testing And Consulting Services, Inc - July 2005

SCRUBBER B
No. 3 Boiler
RAYONIER
Bias/Drift Correction Calculation Spreadsheet

	Scrubber B				Scrubber B		
	BARK				OIL/BARK		
	Date	7/8/05	7/8/05	7/8/05	Date	7/8/05	7/8/05
	Start	8:59	10:22	11:38	Start	13:58	15:08
	Stop	9:59	11:22	12:38	Stop	14:58	16:08
REFERENCE METHOD BIAS ADJUSTED VALUES	**PRELIM**	**1**	**2**	**3**	**PRELIM**	**1**	**2**
O2 (%V,dry)	#N/A	12.2	12.6	12.4	#N/A	12.0	12.0
NOX (ppmV,dry)	#N/A	56.7	51.2	52.6	#N/A	64.9	65.0
CO (ppmV,dry)	#N/A	292.6	243.6	293.6	#N/A	44.4	38.5
RAW AVERAGES	**PRELIM**	**1**	**2**	**3**	**PRELIM**	**1**	**2**
O2 (%V,dry)	#N/A	12.18	12.64	12.45	#N/A	12.10	12.10
NOX (ppmV,dry)	#N/A	57.2	51.7	53.1	#N/A	65.1	65.1
CO(ppmvw)	#N/A	293.0	244.0	294.0	#N/A	44.4	38.5
ZERO BIAS	**PRELIM**	**1**	**2**	**3**	**PRELIM**	**1**	**2**
O2 (%V,dry)	0.02	0.04	0.03	0.02	0.06	0.05	0.06
NOX (ppmV,dry)	0.5	0.5	0.4	0.6	0.8	0.5	0.5
CO(ppmvw)	0.4	0.4	0.4	0.4	0.6	0.5	0.4
BIAS CHECKS	**PRELIM**	**1**	**2**	**3**	**PRELIM**	**1**	**2**
O2 (%V,dry)	12.52	12.56	12.57	12.50	12.57	12.60	12.60
NOX (ppmV,dry)	44.7	44.4	44.4	43.6	94.4	94.4	94.1
CO(ppmvw)	305.0	310.0	300.0	295.0	96.6	95.6	96.8
BIAS VALUES	**PRELIM**	**1**	**2**	**3**	**PRELIM**	**1**	**2**
O2 (%V,dry)	12.53	12.53	12.53	12.53	12.53	12.53	12.53
NOX (ppmV,dry)	44.4	44.4	44.4	44.4	94.4	94.4	94.4
CO(ppmvw)	305.0	306.0	306.0	306.0	96.8	96.8	96.8
ZERO Drift/Bias (% of scale)	**SCALE**	**1**	**2**	**3**	**SCALE**	**1**	**2**
O2 (%V,dry)	25	0.08%	-0.04%	-0.04%	25	-0.04%	0.04%
NOX (ppmV,dry)	100	0.00%	-0.10%	0.20%	100	-0.30%	0.02%
CO(ppmvw)	1000	0.00%	0.00%	0.00%	100	-0.10%	-0.10%
UPSCALE Drift/Bias (% of scale)	**SCALE**	**1**	**2**	**3**	**SCALE**	**1**	**2**
O2 (%V,dry)	25	0.16%	0.04%	-0.28%	25	0.12%	0.00%
NOX (ppmV,dry)	100	-0.30%	0.00%	-0.80%	100	0.00%	-0.30%
CO(ppmvw)	1000	0.50%	-1.00%	-0.50%	100	-1.00%	1.20%

Reference: Source Testing And Consulting Services, Inc - July 2005

APPENDIX B

CALIBRATION DATA AND CERTIFICATES

Rayonier - Fernandina - Alternate Approach to Calculating Heat Input & NOX lb/MMBtu
B-Scrubber - July 14, 2005 Tests - BARK & Oil

Parameter		Units		Run 1	Run 2	Run 3	Average
Inputs							
O2		%V,d		12.6	13.2	12.4	12.7
NOX		ppmVd		73.2	69.8	72	71.7
NOX		ppmVd	@3%O2	157.9	162.3	151.6	157.3
Vol. Flow		dscfm		92,671	94,189	91,300	92720.02
Oil Fd		dscf/MMBtu@0%O2		9190	9190	9190	9190
Bark Fd		dscf/MMBtu@0%O2		9600	9600	9600	9600
Oil Flow		gal/hr		894.6	904.7	921.6	907.0
Oil GCV		Btu/gal		163105	163105	163105	163105
Calculated Values							
Heat Input from Oil:		MMBtu/hr	Gross	145.9	147.6	150.3	147.9
Volumetric Flow From Oil Only		dscfm		56276.7	61348.2	56613.5	58079.5
From Bark Only		dscfm		36394.2	32840.9	34686.5	34640.6
Heat Input From Bark		MMBtu/hr		90.3	75.6	88.2	84.7
Total Heat Input		MMBtu/hr		236.2	223.2	238.5	232.6
Weighted Fd		dscf/MMBtu@0%O2		9346.8	9328.9	9341.6	9339.1
NOX	Fd Method	lb/MMBtu		0.2057	0.2110	0.1975	0.2047
NOX		ppmV@3%O2		157.9	162.3	151.6	157.3
NOX	from Heat Input	lb/hr		48.6	47.1	47.1	47.6
NOX	from Flow	lb/hr		48.6	47.1	47.1	47.6

Reference: Source Testing And Consulting Services, Inc. 2005

Rayonier - Fernandina - Alternate Approach to Calculating Heat Input & NOX lb/MMBtu
B-Scrubber - July 8, 2005 Tests OIL and BARK

Parameter		Units		Run 1	Run 2	Average
Inputs						
O2		%V,d		12.0	12.0	12
NOX		ppmVd		64.9	65.0	65.0
NOX		ppmVd	@3%O2	130.5	130.7	130.6
Vol. Flow		dscfm		93,666	96,033	94849.5
Oil Fd		dscf/MMBtu@0%O2		9190	9190	9190
Bark Fd		dscf/MMBtu@0%O2		9600	9600	9600
Oil Flow		lb/hr or gal/hr				
Oil GCV		Btu/gal or Btu/lb				
Calculated Values						
Heat Input from Oil:		MMBtu/hr	Gross	124	125	124.5
Volumetric Flow From Oil Only		dscfm		44600.8	44960.4	44780.6
From Bark Only		dscfm		49065.2	51072.6	50068.9
Heat Input From Bark		MMBtu/hr		130.6	135.9	133.3
Total Heat Input		MMBtu/hr		254.6	260.9	257.8
Weighted Fd		dscf/MMBtu@0%O2		9400.3	9403.6	9401.9
NOX	Fd Method	lb/MMBtu		0.1711	0.1714	0.1712
NOX		ppmV@3%O2		130.5	130.7	130.6
NOX	from Heat Input	lb/hr		43.5	44.7	44.1
NOX	from Flow	lb/hr		43.5	44.7	44.1

Reference: Source Testing And Consulting Services, Inc. 2005

Rayonier - Fernandina - Alternate Approach to Calculating Heat Input & NOX lb/MMBtu
B-Scrubber - July 8, 2005 Tests - BARK only.

Parameter		Units		Run 1	Run 2	Run 3	Average
Inputs							
O2		%V,d		12.2	12.6	12.4	12.4
NOX		ppmVd		56.7	51.2	52.6	53.5
NOX		ppmVd	@3%O2	116.7	110.4	110.8	112.6
Vol. Flow		dscfm		83,235	86,528	89,438	86400.33
Oil Fd		dscf/MMBtu@0%O2		9190	9190	9190	9190
Bark Fd		dscf/MMBtu@0%O2		9600	9600	9600	9600
Oil Flow		lb/hr or gal/hr					
Oil GCV		Btu/gal or Btu/lb					
Calculated Values							
Heat Input from Oil:		MMBtu/hr	Gross	0	1	5	2.0
Volumetric Flow From Oil Only		dscfm		0.0	385.7	1883.0	756.2
From Bark Only		dscfm		83235.0	86142.3	87555.0	85644.1
Heat Input From Bark		MMBtu/hr		216.6	213.8	222.6	217.6
Total Heat Input		MMBtu/hr		216.6	214.8	227.6	219.6
Weighted Fd		dscf/MMBtu@0%O2		9600.0	9598.1	9591.0	9596.4
NOX	Fd Method	lb/MMBtu		0.1561	0.1477	0.1481	0.1507
NOX		ppmV@3%O2		116.7	110.4	110.8	112.6
NOX	from Heat Input	lb/hr		33.8	31.7	33.7	33.1
NOX	from Flow	lb/hr		33.8 Check OK - JWM	31.7	33.7	33.1

Reference: Source Testing And Consulting Services, Inc. 2005

Source Testing And Consulting Services, Inc.

SRB

6/8/2005 RAYONIER Unit # SRB

	Parameter	O2	NOx	SO2	CO	CO2	NOX	SO2	0	Comments		
	Units	%V	ppmV	ppmV	ppmV	%	@7%O2	@7%O2	0			
6/8/05	13:41:21	4.90	619.15	30.42	1.82	14.54	537.87	26.43		RA R8 PM R3		
6/8/05	13:42:22	4.88	622.06	29.73	1.82	14.61	539.61	25.79		RA R8 PM R3		
6/8/05	13:43:22	4.95	624.03	28.16	1.82	14.53	543.81	24.54		RA R8 PM R3		
6/8/05	13:44:22	4.88	624.13	26.88	1.82	14.65	541.56	23.32		RA R8 PM R3		
6/8/05	13:45:22	4.90	620.10	26.19	1.92	14.64	538.73	22.75		RA R8 PM R3		
6/8/05	13:46:22	4.88	623.15	24.91	1.82	14.63	540.71	21.62		RA R8 PM R3		
6/8/05	13:47:22	4.78	620.10	24.13	0.93	14.67	534.70	20.81		RA R8 PM R3		
6/8/05	13:48:22	4.86	624.13	23.73	1.92	14.61	540.90	20.57		RA R8 PM R3		
6/8/05	13:49:22	4.82	622.06	22.56	1.82	14.63	537.63	19.49		RA R8 PM R3		
6/8/05	13:50:22	4.88	618.03	22.06	0.93	14.57	536.19	19.14		RA R8 PM R3		
6/8/05	13:51:22	4.89	617.15	21.67	1.92	14.60	535.84	18.82		RA R8 PM R3		
6/8/05	13:52:22	4.87	627.08	21.08	1.82	14.57	543.79	18.28		RA R8 PM R3		
6/8/05	13:53:22	4.91	626.09	20.79	1.82	14.59	544.19	18.07		RA R8 PM R3		
6/8/05	13:54:22	4.95	635.04	20.39	1.82	14.57	553.49	17.77		RA R8 PM R3	STOP	STOP PM R3
		4.88	630.21	17.96	2.61	14.68	546.85	15.57		AVG		

Source Testing And Consulting Services, Inc.
SRB

6/8/2005 RAYONIER Unit # SRB

	Parameter	O2	NOx	SO2	CO	CO2	NOX	SO2	0	Comments		
	Units	%V	ppmV	ppmV	ppmV	%	@7%O2	@7%O2	0			
6/8/05	12:11:10	4.28	567.15	102.62	124.02	15.05	474.22	85.81		RA R6 PM R2		
6/8/05	12:12:10	4.24	562.14	114.29	190.65	15.03	469.13	95.38		RA R6 PM R2		
6/8/05	12:13:10	4.28	569.11	116.95	183.48	15.03	476.00	97.82		RA R6 PM R2		
6/8/05	12:14:11	4.28	556.14	109.78	287.36	15.01	465.02	91.79		RA R6 PM R2		
6/8/05	12:15:11	4.25	563.12	112.25	231.83	15.11	470.09	93.71		RA R6 PM R2		
6/8/05	12:16:11	4.23	572.16	110.68	168.35	15.10	477.00	92.27		RA R6 PM R2		
6/8/05	12:17:19	4.22	575.11	110.88	208.44	15.10	479.18	92.38		RA R6 PM R2		
6/8/05	12:18:20	4.15	567.15	110.68	321.56	15.13	470.74	91.87		RA R6 PM R2		
6/8/05	12:19:20	4.30	558.11	110.19	569.41	15.04	467.28	92.26		RA R6 PM R2		
6/8/05	12:20:20	4.24	557.12	118.32	-0.29	15.09	464.81	98.72		RA R6 PM R2		
6/8/05	12:21:20	4.30	559.09	119.01	170.31	15.10	468.17	99.66		RA R6 PM R2	STOP	
		4.29	576.79	119.84	160.89	15.12	482.84	100.35		AVG		
6/8/05	12:53:19	4.73	626.14	25.16	1.87	14.74	538.36	21.63		RAR7 PM R3	START	START PM RUN 3 12:49
6/8/05	12:54:19	4.72	629.19	19.75	1.87	14.77	540.65	16.97		RAR7 PM R3		
6/8/05	12:55:19	4.80	631.06	16.22	1.87	14.75	544.90	14.00		RAR7 PM R3		
6/8/05	12:56:19	4.71	633.12	13.46	1.87	14.84	543.45	11.56		RAR7 PM R3		
6/8/05	12:57:19	4.81	628.21	11.20	1.87	14.80	542.69	9.68		RAR7 PM R3		
6/8/05	12:58:19	4.79	634.10	8.75	1.87	14.83	547.11	7.55		RAR7 PM R3		
6/8/05	12:59:19	4.77	632.14	6.49	1.87	14.84	544.84	5.59		RAR7 PM R3		
6/8/05	13:00:19	4.89	635.09	4.32	1.87	14.72	551.24	3.75		RAR7 PM R3		
6/8/05	13:01:19	4.92	637.15	2.75	1.87	14.77	554.05	2.39		RAR7 PM R3		
6/8/05	13:02:19	4.86	639.12	2.89	1.87	14.80	553.97	2.50		RAR7 PM R3		
6/8/05	13:03:19	4.91	637.15	2.49	1.97	14.77	553.80	2.17		RAR7 PM R3		
6/8/05	13:04:21	4.92	631.16	2.08	2.85	14.80	548.92	1.81		RAR7 PM R3		
6/8/05	13:05:21	4.87	637.15	2.47	1.87	14.82	552.52	2.15		RAR7 PM R3		
6/8/05	13:06:21	4.84	631.16	3.87	1.87	14.83	546.15	3.35		RAR7 PM R3		
6/8/05	13:07:21	4.99	633.22	6.39	1.87	14.74	553.36	5.58		RAR7 PM R3		
6/8/05	13:08:22	4.90	641.08	5.80	1.87	14.80	557.04	5.04		RAR7 PM R3		
6/8/05	13:09:21	4.84	638.13	6.19	1.87	14.83	552.36	5.36		RAR7 PM R3		
6/8/05	13:10:24	5.04	647.17	6.58	1.87	14.73	567.13	5.77		RAR7 PM R3		
6/8/05	13:11:24	5.06	656.12	6.29	1.87	14.70	575.86	5.52		RAR7 PM R3		
6/8/05	13:12:24	4.99	654.15	6.78	2.85	14.69	571.65	5.93		RAR7 PM R3		
6/8/05	13:13:24	5.01	657.10	8.06	1.87	14.72	574.85	7.05		RAR7 PM R3	STOP	
6/8/05	13:33:22	4.86	624.16	40.64	34.06	14.59	540.97	35.22		RA R8 PM R3	START	
6/8/05	13:34:21	4.97	633.20	31.21	1.92	14.52	552.37	27.22		RA R8 PM R3		
6/8/05	13:35:21	4.91	631.14	31.21	1.82	14.54	548.70	27.13		RA R8 PM R3		
6/8/05	13:36:21	4.89	626.12	31.60	1.82	14.58	543.59	27.43		RA R8 PM R3		
6/8/05	13:37:21	4.87	618.07	32.19	1.92	14.59	536.10	27.92		RA R8 PM R3		
6/8/05	13:38:21	4.87	623.18	31.89	1.92	14.60	540.45	27.66		RA R8 PM R3		
6/8/05	13:39:21	4.93	617.08	31.60	1.92	14.52	537.15	27.51		RA R8 PM R3		
6/8/05	13:40:21	4.81	615.12	31.11	1.82	14.65	531.35	26.87		RA R8 PM R3		

Source Testing And Consulting Services, Inc.
SRB

6/8/2005 RAYONIER Unit # SRB

	Parameter	O2	NOx	SO2	CO	CO2	NOX	SO2	0	Comments		
	Units	%V	ppmV	ppmV	ppmV	%	@7%O2	@7%O2	0			
6/8/05	11:07:06	4.33	586.09	130.49	151.20	15.21	491.74	109.48		RAR4		
6/8/05	11:08:06	4.43	583.05	123.31	40.15	15.16	492.03	104.06		RAR4		
6/8/05	11:09:06	4.40	576.17	124.92	54.20	15.18	485.36	105.23		RAR4		
6/8/05	11:10:06	4.73	584.13	123.33	28.94	14.94	502.08	106.01		RAR4		
6/8/05	11:11:06	4.32	588.06	129.59	149.04	15.32	492.95	108.63		RAR4		
6/8/05	11:12:06	4.32	576.07	128.33	175.28	15.30	483.04	107.61		RAR4		
6/8/05	11:13:06	4.33	582.16	126.56	179.41	15.34	488.22	106.14		RAR4		
6/8/05	11:14:06	4.25	584.03	124.89	207.52	15.31	487.48	104.24		RAR4		
6/8/05	11:15:06	4.28	585.11	119.91	231.89	15.35	489.46	100.31		RAR4	CAL	
6/8/05	11:26:34	4.28	577.10	111.47	199.80	14.99	482.76	93.25		RA R5 PM R2	START	
6/8/05	11:27:34	4.19	563.15	117.86	257.20	15.09	468.39	98.03		RA R5 PM R2		
6/8/05	11:28:34	4.21	562.06	112.09	225.75	15.11	468.11	93.35		RA R5 PM R2		
6/8/05	11:29:34	4.21	567.08	127.49	128.06	15.04	472.14	106.15		RA R5 PM R2		
6/8/05	11:30:34	4.22	553.12	123.88	206.59	15.07	460.86	103.22		RA R5 PM R2		
6/8/05	11:31:34	4.32	571.20	120.17	188.60	15.02	478.89	100.75		RA R5 PM R2		
6/8/05	11:32:34	4.21	567.08	125.48	147.13	15.11	472.28	104.50		RA R5 PM R2		
6/8/05	11:33:34	4.22	579.17	118.33	173.27	15.10	482.71	98.62		RA R5 PM R2		
6/8/05	11:34:34	4.28	577.10	111.59	215.63	15.05	482.62	93.32		RA R5 PM R2		
6/8/05	11:35:34	4.21	578.18	113.49	183.49	15.14	481.53	94.52		RA R5 PM R2		
6/8/05	11:36:34	4.21	588.21	114.10	168.35	15.12	489.74	95.00		RA R5 PM R2		
6/8/05	11:37:34	4.28	582.21	115.31	110.96	15.11	486.89	96.43		RA R5 PM R2		
6/8/05	11:38:34	4.32	572.19	114.41	246.09	15.04	479.79	95.93		RA R5 PM R2		
6/8/05	11:39:34	4.23	574.25	111.02	73.22	15.10	478.89	92.58		RA R5 PM R2		
6/8/05	11:40:34	4.22	575.14	111.46	88.35	15.09	479.21	92.87		RA R5 PM R2		
6/8/05	11:41:34	4.26	575.21	113.33	84.32	15.06	480.39	94.65		RA R5 PM R2		
6/8/05	11:42:34	4.28	573.14	114.22	158.32	15.05	479.37	95.53		RA R5 PM R2		
6/8/05	11:43:34	4.34	585.13	111.38	69.48	15.01	491.22	93.50		RA R5 PM R2		
6/8/05	11:44:34	4.25	589.06	110.27	72.43	15.09	491.82	92.06		RA R5 PM R2		
6/8/05	11:45:34	4.34	582.08	111.59	80.29	15.01	488.66	93.68		RA R5 PM R2		
6/8/05	11:46:34	4.26	588.18	121.51	100.54	15.07	491.44	101.53		RA R5 PM R2	CAL	
6/8/05	11:47:34	4.32	585.13	111.22	101.62	15.04	490.42	93.22		RA R5 PM R2	STOP	
6/8/05	12:00:10	4.36	559.19	108.35	126.09	14.99	469.99	91.07		RA R6 PM R2	START	
6/8/05	12:01:10	4.30	563.12	111.31	128.05	15.02	471.55	93.21		RA R6 PM R2		
6/8/05	12:02:10	4.29	562.14	101.59	221.61	15.04	470.45	85.02		RA R6 PM R2		
6/8/05	12:03:10	4.31	559.19	114.34	116.85	15.07	468.39	95.78		RA R6 PM R2		
6/8/05	12:04:10	4.21	558.11	110.62	181.42	15.16	464.74	92.11		RA R6 PM R2		
6/8/05	12:05:10	4.27	570.10	107.00	130.12	15.12	476.54	89.44		RA R6 PM R2		
6/8/05	12:06:10	4.25	575.11	104.83	228.79	15.13	480.10	87.51		RA R6 PM R2		
6/8/05	12:07:10	4.21	573.14	104.15	256.20	15.14	477.26	86.72		RA R6 PM R2		
6/8/05	12:08:10	4.24	585.13	105.03	158.32	15.10	488.32	87.65		RA R6 PM R2		END PM R2
6/8/05	12:09:10	4.19	565.08	103.65	256.20	15.16	470.13	86.24		RA R6 PM R2		12:08
6/8/05	12:10:10	4.00	564.10	104.88	372.27	15.04	463.92	86.26		RA R6 PM R2		

Source Testing And Consulting Services, Inc.
SRB

6/8/2005		RAYONIER							Unit #	SRB			
	Parameter	O2	NOx	SO2	CO	CO2	NOX	SO2	0	Comments			
	Units	%V	ppmV	ppmV	ppmV	%	@7%O2	@7%O2	0				
6/8/05	9:56:38	4.66	585.14	293.92	1.82	15.07	500.79	251.55		RA R2 PM R1			
6/8/05	9:57:38	4.66	583.08	295.30	1.92	15.07	499.17	252.80		RA R2 PM R1			
6/8/05	9:58:38	4.48	584.06	297.46	2.90	15.20	494.33	251.76		RA R2 PM R1			
6/8/05	9:59:38	4.50	576.20	302.37	5.85	15.19	488.48	256.34		RA R2 PM R1			
6/8/05	10:00:38	4.52	576.10	306.90	2.80	15.14	488.91	260.45		RA R2 PM R1	STOP	END PM RUN 1	
6/8/05	10:20:09	4.49	568.13	250.90	10.81	15.14	481.37	212.58		RAR3 PMR2	START	PM R2 START	11:05
6/8/05	10:21:09	4.47	568.13	245.98	7.96	15.13	480.73	208.14		RAR3 PMR2			
6/8/05	10:22:09	4.43	568.14	222.37	16.86	15.21	479.38	187.63		RAR3 PMR2			
6/8/05	10:23:09	4.50	581.11	216.96	8.80	15.20	492.53	183.89		RAR3 PMR2			
6/8/05	10:24:09	4.50	583.08	213.23	5.95	15.17	494.05	180.67		RAR3 PMR2			
6/8/05	10:25:09	4.58	593.10	208.91	7.91	15.13	505.27	177.97		RAR3 PMR2			
6/8/05	10:26:09	4.39	590.15	204.29	10.66	15.31	496.99	172.04		RAR3 PMR2			
6/8/05	10:27:09	4.52	574.13	198.09	57.35	15.22	487.20	168.10		RAR3 PMR2			
6/8/05	10:28:09	4.57	582.09	195.24	14.69	15.19	495.44	166.18		RAR3 PMR2			
6/8/05	10:29:09	4.47	572.17	192.88	19.80	15.33	483.94	163.14		RAR3 PMR2			
6/8/05	10:30:09	4.51	582.19	189.35	10.76	15.26	493.89	160.63		RAR3 PMR2			
6/8/05	10:31:09	4.55	579.05	186.50	26.00	15.27	492.18	158.52		RAR3 PMR2			
6/8/05	10:32:09	4.48	575.11	183.35	17.84	15.29	486.72	155.17		RAR3 PMR2			
6/8/05	10:33:09	4.47	586.12	180.70	10.76	15.34	495.96	152.90		RAR3 PMR2			
6/8/05	10:34:09	4.47	600.57	176.86	6.73	13.85	478.82	141.01		RAR3 PMR2			
6/8/05	10:35:09	4.39	592.02	175.88	20.89	15.35	498.57	148.12		RAR3 PMR2			
6/8/05	10:36:09	4.58	605.09	173.42	16.86	15.24	515.25	147.68		RAR3 PMR2			
6/8/05	10:37:09	4.35	588.48	172.83	11.75	15.41	494.19	145.14		RAR3 PMR2			
6/8/05	10:38:09	4.56	579.14	169.20	89.49	15.28	492.56	143.90		RAR3 PMR2			
6/8/05	10:39:09	4.59	594.18	167.92	9.78	15.25	506.27	143.07		RAR3 PMR2			
6/8/05	10:40:09	4.43	594.38	167.72	17.94	15.37	501.67	141.56		RAR3 PMR2			
6/8/05	10:41:09	4.51	588.19	165.17	42.12	15.36	498.98	140.12		RAR3 PMR2	STOP		
		4.72	590.07	218.39	8.47	15.14	506.73	187.29					
6/8/05	10:54:06	4.47	600.08	147.53	9.78	15.10	507.81	124.84		RAR4	START		
6/8/05	10:55:06	4.39	609.12	156.35	23.93	15.15	512.85	131.64		RAR4			
6/8/05	10:56:06	4.51	610.10	143.50	53.22	15.07	517.46	121.71		RAR4			
6/8/05	10:57:06	4.18	596.15	142.02	156.22	15.34	495.52	118.05		RAR4			
6/8/05	10:58:06	4.32	564.21	145.54	576.59	15.27	473.14	122.04		RAR4			
6/8/05	10:59:06	4.41	587.11	141.21	82.41	15.18	494.83	119.02		RAR4			
6/8/05	11:00:06	4.30	584.16	140.72	162.42	15.26	489.21	117.85		RAR4			
6/8/05	11:01:06	4.45	591.14	138.85	72.39	15.15	499.42	117.31		RAR4			
6/8/05	11:02:06	4.35	589.14	137.17	79.26	15.24	494.81	115.21		RAR4			
6/8/05	11:03:06	4.38	585.11	135.21	93.51	15.22	492.45	113.80		RAR4			
6/8/05	11:04:06	4.40	601.13	133.44	37.10	15.14	506.46	112.42		RAR4			
6/8/05	11:05:06	4.34	598.08	132.65	91.35	15.23	501.87	111.31		RAR4		PM RUN 2	
6/8/05	11:06:06	4.42	602.11	130.98	52.14	15.18	507.89	110.49		RAR4		START 11:05	