Memorandum

Florida Department of Environmental Protection

To: Trina Vielhauer, Bureau of Air Regulation

Through: Jeff Koerner, New Source Review Section

From: Bruce Mitchell, New Source Review Section

Date: July 7, 2008

Subject: Revised Draft Air Permit No. PSD-FL-397
Project No. 1230001-023-AC
Buckeye Florida Foley Mill
Foley Energy Independence Project

This project is subject to PSD preconstruction review. Attached for your review are the following items for the revised draft permit package:

- Written Notice of Intent to Issue Air Permit;
- Public Notice of Intent to Issue Air Permit;
- Technical Evaluation and Preliminary Determination (including BACT determinations);
- Draft Permit with Appendices; and
- P.E. Certification.

The Draft Permit authorizes the following work: conversion of the Nos. 2 and 3 Recovery Boilers from direct contact evaporator units to low-odor, non-direct contact evaporator units; permanent shutdown of the black liquor oxidation system once conversion of the recovery boilers is complete; addition of two new forced-circulation/crystallizer black liquor concentrators and a black liquor storage tank to the existing multiple effect evaporator system; installation of a new 28 megawatt condensing steam turbine-electrical generator set; and miscellaneous common system changes including piping, ductwork, pumps, tanks, etc. The proposed work will be conducted at existing Foley Mill, which is located in Taylor County at One Buckeye Drive in Perry, Florida. The Technical Evaluation and Preliminary Determination provides a detailed description of the project and the rationale for issuance. I recommend your approval of the attached Draft Permit.

Attachments

TLV/jfk/bm

Florida Department of Environmental Protection

Bob Martinez Center
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Charlie Crist
Governor

Jeff Kottkamp
Lt. Governor

Michael W. Sole
Secretary

July 7, 2008

Sent Electronically – Received Receipt Requested

Mr. Howard Drew
Vice President of Wood Cellulose Manufacturing
Buckeye Florida, Limited Partnership
One Buckeye Drive
Perry, Florida 32348

Re: Revised Draft Permit Package
Draft Air Permit No. PSD-FL-397
Project No. 1230001-023-AC
Buckeye Florida, Limited Partnership, Foley Mill
Foley Energy Independence Project

Dear Mr. Drew:

On December 11, 2007, Buckeye Florida, Limited Partnership submitted an application for the Foley Energy Independence Project at the existing Foley Mill, which is located in Taylor County at One Buckeye Drive in Perry, Florida. The previous draft permit package issued on June 13, 2008 is hereby rescinded and replaced with this revised draft permit package. Enclosed are the following revised documents: Technical Evaluation and Preliminary Determination, Draft Permit with Appendices, Written Notice of Intent to Issue Air Permit and Public Notice of Intent to Issue Air Permit. The Public Notice of Intent to Issue Air Permit is the actual notice that you must have published in the legal advertisement section of a newspaper of general circulation in the area affected by this project. If you have any questions, please contact the project engineer, Bruce Mitchell, at 850/413-9198.

Sincerely,

Trina L. Vielhauer

Trina Vielhauer, Chief
Bureau of Air Regulation

TLV/jfk/bm

Enclosures

WRITTEN NOTICE OF INTENT TO ISSUE AIR PERMIT

In the Matter of an
Application for Air Permit by:

Buckeye Florida, Limited Partnership
One Buckeye Drive
Perry, Florida 32348

Authorized Representative:
Mr. Howard Drew, V.P. of Wood Cellulose Manufacturing

Revised Draft
Draft Air Permit No. PSD-FL-397
Project No. 1230001-023-AC
Buckeye Florida Foley Mill
Foley Energy Independence Project
Taylor County, Florida

Facility Location: Buckeye Florida, Limited Partnership operates an existing dissolving grade Kraft process pulp mill in Taylor County at One Buckeye Drive, which is east of US 19, south of SR 30, and southeast of Perry, Florida.

Project: On December 11, 2007, Buckeye Florida, Limited Partnership submitted an application for an air construction permit for the Foley Energy Independence Project at the existing Foley Mill. Pursuant to Rule 62-212.400 of the Florida Administrative Code (F.A.C.), the project is subject to preconstruction review in accordance with the requirements for the prevention of significant deterioration (PSD) of air quality for emissions of carbon monoxide, nitrogen oxides, particulate matter, and particulate matter with an aerodynamic diameter of 10 microns or less. Details of the project are provided in the attached Technical Evaluation and Preliminary Determination as well as the revised Draft Permit package.

Permitting Authority: Applications for air construction permits are subject to review in accordance with the provisions of Chapter 403, Florida Statutes (F.S.), and Chapters 62-4, 62-210, and 62-212, F.A.C. The proposed project is not exempt from air permitting requirements and an air permit is required to perform the proposed work. The Florida Department of Environmental Protection's Bureau of Air Regulation is the Permitting Authority responsible for making a permit determination for this project. The Bureau of Air Regulation's physical address is 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301 and the mailing address is 2600 Blair Stone Road, MS #5505, Tallahassee, Florida 32399-2400. The Bureau of Air Regulation's phone number is 850/488-0114.

Project File: A complete project file is available for public inspection during the normal business hours of 8:00 a.m. to 5:00 p.m., Monday through Friday (except legal holidays), at address indicated above for the Permitting Authority. The complete project file includes the Draft Permit, the Technical Evaluation and Preliminary Determination, the application, and the information submitted by the applicant, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Permitting Authority's project review engineer for additional information at the address and phone number listed above.

Notice of Intent to Issue Air Permit: The Permitting Authority gives notice of its intent to issue an air permit to the applicant for the project described above. The previous draft permit package issued on June 13, 2008 is hereby rescinded and replaced with this revised draft permit package. The applicant has provided reasonable assurance that operation of the proposed equipment will not adversely impact air quality and that the project will comply with all applicable provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297, F.A.C. The Permitting Authority will issue a Final Permit in accordance with the conditions of the proposed Draft Permit unless a timely petition for an administrative hearing is filed under Sections 120.569 and 120.57, F.S., or unless public comment received in accordance with this notice results in a different decision or a significant change of terms or conditions.

Public Notice: Pursuant to Section 403.815, F.S., and Rules 62-110.106 and 62-210.350, F.A.C., you (the applicant) are required to publish at your own expense the enclosed Public Notice of Intent to Issue Air Permit (Public Notice). The Public 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 by this project. The newspaper used must meet 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 phone number listed above. Pursuant to Rules 62-110.106(5) and (9), F.A.C., the applicant shall provide proof of publication to the Permitting Authority at the above address within 7 days of publication. Failure to publish the notice and provide proof of publication may result in the denial of the permit pursuant to Rule 62-110.106(11), F.A.C.

Comments: The Permitting Authority will accept written comments concerning the proposed Draft Permit and requests for a public meeting for a period of 30 days from the date of publication of the Public Notice. Written comments must be received by the Permitting Authority by close of business (5:00 p.m.) on or before the end of this 30-day period. In addition, if a public meeting is requested within the 30-day comment period and conducted by the Permitting Authority, any oral and written comments received during the public meeting will also be considered by the Permitting Authority. If timely received comments result in a significant change to the Draft Permit, the Permitting Authority shall revise the Draft Permit and require, if applicable, another Public Notice. All comments filed will be made available for public inspection.

Petitions: 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 with (received by) the Department's Agency Clerk 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 applicant or any of the parties listed below must be filed within 14 days of receipt of this Written Notice of Intent to Issue Air Permit. Petitions filed by any persons other than those entitled to written notice under Section 120.60(3), F.S., must be filed within 14 days of publication of the attached Public Notice or within 14 days of receipt of this Written Notice of Intent to Issue Air Permit, 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 14 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 (in a proceeding initiated by another party) 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 when and how each petitioner received notice of the agency action or decision; (d) A statement of all disputed issues of material fact; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action including an explanation of how the alleged facts relate to the specific rules or statutes; and, (g) A statement of the relief sought by the petitioner, stating precisely the action the 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 Written Notice of Intent to Issue Air Permit. 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: Mediation is not available in this proceeding.

Executed in Tallahassee, Florida.

Trina L Vielhauer

Trina Vielhauer, Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Written Notice of Intent to Issue Air Permit package (including the Public Notice, the Technical Evaluation and Preliminary Determination, and the Draft Permit) was sent electronically (received receipt requested) before the close of business on 7/7/08 to the persons listed below.

Mr. Howard Drew, Buckeye Florida, Limited Partnership (howard_drew@bkitech.com)
Mr. David Weeden, Buckeye Florida, Limited Partnership (dave_weeden@bkitech.com)
Mr. Ray Perry, Buckeye Florida, Limited Partnership (ray_perry@bkitech.com)
Mr. David A. Buff, P.E., Golder Associates, Inc. (dbuff@golder.com)
Mr. Christopher Kirts, Northeast District Office (Christopher.Kirts@dep.state.fl.us)
Ms. Kathleen Forney, U.S. EPA, Region 4 (Forney.Kathleen@epamail.epa.gov)
Mr. Dee Morse, National Park Service (dee_morse@nps.gov)

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 (Clerk) 7/7/08 (Date)

PUBLIC NOTICE OF INTENT TO ISSUE AIR PERMIT

Florida Department of Environmental Protection
Division of Air Resource Management, Bureau of Air Regulation
Draft Air Permit No. PSD-FL-397 / Project No. 1230001-023-AC
Buckeye Florida, Limited Partnership, Foley Energy Independence Project
Taylor County, Florida

Applicant: The applicant for this project is Buckeye Florida, Limited Partnership. The applicant's authorized representative and mailing address is: Mr. Howard Drew, Vice President of Wood Cellulose Manufacturing, Buckeye Florida, Limited Partnership, One Buckeye Drive, Perry, Florida 32348.

Facility Location: Buckeye Florida, Limited Partnership operates an existing dissolving grade Kraft process pulp mill in Taylor County at One Buckeye Drive, which is east of US 19, south of SR 30, and southeast of Perry, Florida.

Project: The applicant, Buckeye Florida, Limited Partnership, submitted an application for an air construction permit for the Foley Energy Independence Project at the existing Foley Mill. The proposed project includes the following work: conversion of the Nos. 2 and 3 Recovery Boilers from direct contact evaporator units to low-odor, non-direct contact evaporator units; permanent shutdown of the black liquor oxidation system once conversion of the recovery boilers is complete; addition of two new forced-circulation/crystallizer black liquor concentrators and a black liquor storage tank to the existing multiple effect evaporator system; installation of a new 28 megawatt condensing steam turbine-electrical generator set; and miscellaneous common system changes including piping, ductwork, pumps, tanks, etc. Only 12 MW are expected to be generated as a result of this project. Future steam improvement projects may take advantage of the additional capacity.

As defined in Rule 62-210.200 of the Florida Administrative Code (F.A.C.) and based on the air permit application, the project potentially results in the following significant net emissions increases: 1715 tons per year of carbon monoxide (CO); 769 tons per year of nitrogen oxides (NO_X); 237 tons per year of particulate matter (PM); and 183 tons per year of particulate matter with an aerodynamic diameter of 10 microns or less (PM_{10}). The project does not result in significant emissions increases of sulfuric acid mist, sulfur dioxide or volatile organic compounds. Pursuant to Rule 62-212.400, F.A.C., the project is subject to PSD preconstruction review for CO, NO_X, and PM/PM_{10} emissions, which requires determinations of the Best Available Control Technology (BACT) for the PSD-significant pollutants.

The Nos. 2 and 3 Recovery Boilers will be the only units being modified or constructed that emit the PSD-significant pollutants. Therefore, the Department made preliminary BACT determinations for the Nos. 2 and 3 Recovery Boilers based on the following: an electrostatic precipitator to control and minimize PM/PM_{10} emissions and stack opacity; and boiler design and operating practices to minimize CO and NO_X emissions. The provisions regulating PM emissions will serve as a surrogate for controlling PM_{10} emissions. To ensure compliance with the new BACT standards, the draft permit requires continuous monitoring and recording of opacity, CO emissions and NO_X emissions.

The Department reviewed an air quality analysis prepared by the applicant. There is no predicted significant impact on the PSD Class I increments in the St. Marks National Wilderness Area, which is the closest PSD Class I area to the facility. The following table shows the maximum predicted PSD Class II increment for nitrogen dioxide (NO_2) consumed by all sources in the area, including this project.

Summary of PSD Class II Increment Analysis

Pollutant	Averaging Time	Allowable Increment (μg/m³)	Increment Consumed (μg/m³)	Percent
NO_2	Annual	25	1.3	5%

The other PSD-significant pollutants were predicted to have no significant impacts in the PSD Class II area in the vicinity of the project. Based on the analysis, emissions from the project will not significantly contribute to, or cause a violation of, any state or federal ambient air quality standards.

A draft permit was originally issued for this project on June 13, 2008. The applicant filed a request for an extension of time in which to file a petition. The applicant and the Department reached a mutual agreement to clarify several conditions of the original permit and issue a revised draft permit for publication. The previous draft permit package is hereby rescinded and replaced with the revised draft permit package.

Permitting Authority: Applications for air construction permits are subject to review in accordance with the provisions of Chapter 403, Florida Statutes (F.S.), and Chapters 62-4, 62-210, and 62-212, F.A.C. The proposed project is not exempt from air permitting requirements and an air permit is required to perform the proposed work. The Florida Department of Environmental Protection's Bureau of Air Regulation is the Permitting Authority responsible for making a permit determination for this project. The Bureau of Air Regulation's physical address is 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, and the mailing address is 2600 Blair Stone Road, MS #5505, Tallahassee, Florida 32399-2400. The Bureau of Air Regulation's phone number is 850/488-0114.

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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 when and how each petitioner received notice of the agency action or decision; (d) A statement of all disputed issues of material fact; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action including an explanation of how the alleged facts relate to the specific rules or statutes; and, (g) A statement of the relief sought by the petitioner, stating precisely the action the 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 to Issue Air Permit. 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: Mediation is not available in this proceeding.

(Public Notice to be Published in the Newspaper)

TECHNICAL EVALUATION

&

PRELIMINARY DETERMINATION

APPLICANT

Buckeye Florida, Limited Partnership
One Buckeye Drive
Perry, Florida 32348

PROJECT

Draft Permit No. PSD-FL-397
Project No. 1230001-023-AC

Foley Energy Independence Project

Buckeye Foley Mill
Facility ID No. 1230001

COUNTY

Taylor County, Florida

PERMITTING AUTHORITY

Florida Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation
New Source Review Section
2600 Blair Stone Road, MS#5505
Tallahassee, Florida 32399-2400

July 7, 2008 *Revision*

1. GENERAL PROJECT INFORMATION

Air Pollution Regulations

Projects with the potential to emit air pollution are subject to the applicable environmental laws specified in Section 403 of the Florida Statutes (F.S.). The statutes authorize the Department of Environmental Protection (Department) to establish regulations regarding air quality as part of the Florida Administrative Code (F.A.C.), which includes the following chapters: 62-4 (Permits); 62-204 (Air Pollution Control – General Provisions); 62-210 (Stationary Sources – General Requirements); 62-212 (Stationary Sources – Preconstruction Review); 62-213 (Operation Permits for Major Sources of Air Pollution); 62-296 (Stationary Sources - Emission Standards); and 62-297 (Stationary Sources – Emissions Monitoring). Specifically, air construction permits are required pursuant to Chapters 62-4, 62-210 and 62-212, F.A.C.

In addition, the U. S. Environmental Protection Agency (EPA) establishes air quality regulations in Title 40 of the Code of Federal Regulations (CFR). Part 60 specifies New Source Performance Standards (NSPS) for numerous industrial activities. Part 61 specifies National Emission Standards for Hazardous Air Pollutants (NESHAP) based on specific pollutants. Part 63 specifies NESHAP based on the Maximum Achievable Control Technology (MACT) for numerous industrial categories. The Department adopts these federal regulations on a quarterly basis in Rule 62-204.800, F.A.C.

Facility Description and Location

Buckeye operates an existing dissolving grade Kraft sulfate process pulp mill (SIC No. 2611) in Taylor County at One Buckeye Drive, which is east of US 19, south of SR 30, and southeast of Perry, Florida. The UTM coordinates of this facility are: Zone 17, 256.7 km East, and 3328.7 km North. This site is in an area that is in attainment (or designated as unclassifiable) for each air pollutant subject to a state or federal Ambient Air Quality Standard (AAQS).

In the Kraft process, the digesting liquor (white liquor) is a solution of sodium hydroxide and sodium sulfide that is mixed with wood chips and cooked under pressure. The spent liquor, known as weak black liquor, is concentrated and sodium sulfate is added to make up for chemical losses. The black liquor solids (BLS) are burned in the recovery furnaces to produce a smelt of sodium carbonate and sodium sulfide. The smelt is dissolved in water to form green liquor to which quicklime (calcium oxide) is added to convert the sodium carbonate back to sodium hydroxide, which reconstitutes the cooking liquor. The spent lime cake (calcium carbonate) is recalcined in a rotary lime kiln to produce quicklime, which is used to convert the green liquor to cooking liquor. Steam and energy needs at the plant are met by: combination boilers, which burn bark/wood and residual oil; power boilers, which burn residual oil and natural gas; and recovery boilers, which burn BLS and residual oil.

Primary Regulatory Categories

- The facility is a major source of hazardous air pollutants (HAP).
- The facility has no units subject to the acid rain provisions of the Clean Air Act.
- The facility is a Title V major source of air pollution in accordance with Chapter 213, F.A.C.
- The facility is a major stationary source in accordance with Rule 62-212.400, F.A.C. for the Prevention of Significant Deterioration (PSD) of Air Quality.

Project Description

The applicant, Buckeye Florida, Limited Partnership, submitted an application for an air construction permit for the Foley Energy Independence Project subject to the PSD preconstruction review requirements of Rule 62-212.400, F.A.C. The overall goal of the proposed project is to improve efficiency for steam and electrical equipment at the plant, reduce the amount of electricity purchased from the grid (currently about 120,000 MW-hours per year) and reduce the amount of purchased fossil fuels (currently about 6 million MMBtu per year). The total estimated costs of the proposed project are over $28 million.

The project consists of the following changes.

- Nos. 2 and 3 Recovery Boilers (EU-006 and EU-007): The boilers will be physically modified and converted from direct contact evaporator (DCE) units to low-odor, non-direct contact evaporator (NDCE) units. Conversion of the No. 2 Recovery Boiler includes:
  - Remove the existing cascade evaporator and modify the ductwork;
  - Change the drum internals and feed/riser tubes as necessary;
  - Replace or modify flue ducts from the generating section outlet to the cyclone evaporator outlet;
  - Install a new economizer with new soot blowers;
  - Increase the superheater surface areas by approximately 6%;
  - Install an ash collection system for the new economizer and ducts;
  - Install a new mix tank to mix ash with black liquor; and
  - Install a tertiary air fan as part of the over-fire air system to increase total combustion air by 20%.

  Costs are estimated at $6.3 million for the No. 2 Recovery Boiler and $500,000 for the tertiary air fan. Conversion of the No. 3 Recovery Boiler includes:
  - Remove the existing cascade evaporator and modify the ductwork;
  - Change the drum internals and feed/riser tubes as necessary;
  - Install an additional economizer;
  - Install two new superheater platens to increase surface area;
  - Install a new water coil air heater to preheat and increase the primary air temperature in lower furnace;
  - Install new flue gas duct to connect outlet of existing economizer to inlet of new economizer;
  - Install new flue gas duct to connect outlet of new economizer to inlet of electrostatic precipitator; and
  - Install an ash collection system for the new economizer and ducts.

  Costs are estimated at $7.9 million for the No. 3 Recovery Boiler. Although no physical modifications will be made to the BLS firing system, the maximum heat input rates will increase for both units due to the new concentrators and solids content of the black liquor. There will be no physical changes or increases to the oil firing systems on these units. The following table summarizes the capacities after completing the project.

Parameter	No. 2 Recovery Boiler	No. 3 Recovery Boiler
BLS Firing		
Maximum Steam Production Rate (1-hour)	380,000 lb/hour	325,000 lb/hour
Maximum BLS Firing Rate	97,600 lb/hour	82,350 lb/hour
Maximum Heat Input Rate from BLS	625 MMBtu/hour	527 MMBtu/hour
Heating Value for BLS	6400 Btu/lb	6400 Btu/lb
Oil Firing		
Number of Oil Burners	8	4
Heat Input Rate per Burner	40 MMBtu/hour	20 MMBtu/hour
Heat Input Rate from Oil, Total	320 MMBtu/hour	80 MMBtu/hour

Parameter	No. 2 Recovery Boiler	No. 3 Recovery Boiler
Maximum Oil Firing Rate, Total	2192 gallons/hour	603 gallons/hour*
Maximum Requested Annual Oil Firing Rate	1,700,000 gallons/year	2,000,000 gallons/year
Heating Value for Oil	146,000 Btu/gallon	146,000 Btu/gallon

* As demonstrated in practice, this value represents 10% more than the vendor's specification.

- Multiple Effect Evaporator (MEE) System (EU-046): Two new forced-circulation/crystallizer black liquor concentrators (Nos. 2 and 3) will be installed. Each unit will consist of: two tube and shell heat exchangers; two recirculation pumps; a crystallizer flash tank; a product flash tank; and a product transfer pump. Each new concentrator will be tied into an existing 5-effect black liquor MEE. The maximum capacity of each new concentrator is dependent on the existing MEE (122,356 lb/hour and 127,350 lb/hour for the Nos. 2 and 3 MEE, respectively). The new concentrators will increase the solids content of the BLS from approximately 50% to 72%. A new black liquor storage tank (approximately 132,000 gallons) will be added to store the 72% solids black liquor. Changes will increase the non-condensable gases (NCG) generated from the MEE system, which will be controlled by combustion in the No. 1 Bark Boiler (primary control) or the No. 1 Power Boiler (secondary control), which also controls TRS emissions with a white liquor pre-scrubber. Costs are estimated at $5.5 million for the No. 2 black liquor concentrator and $5.1 million for the No. 3 black liquor concentrator.
- Common System Changes: These changes include miscellaneous equipment needed for both recovery boilers. The preliminary design includes the following items:
  - Install a new black liquor storage tank;
  - Install piping from new concentrators to new and existing storage tanks;
  - Install piping from the concentrated liquor storage tanks to the recovery boiler salt cake mix tanks;
  - Install recirculation pump/piping on concentrated liquor storage tanks to minimize tank cone plugging;
  - Install transfer line between new and existing concentrated liquor storage tanks;
  - Install new recirculation pumps on existing East 50% black liquor storage tank for ash mixing; and
  - Install new recirculation pumps on ash mix tanks.

  The estimated costs for common system changes are $3.0 million.
- BLOX System: After completion of the No. 2 recovery boiler conversion, the maximum throughput of the black liquor oxidation (BLOX) system will be reduced by approximately 54% to support only the No. 3 Recovery Boiler. After completion of the second recovery boiler conversion, the BLOX system will be permanently shutdown.
- New Condensing Steam Turbine-Electrical Generator: The plant currently operates four extraction steam turbine-electrical generators with a total capacity of 39 MW. A new 28 MW condensing steam turbine-electrical generator will be installed to take advantage of the equipment efficiency improvements and additional bark/wood firing. Only 12 MW are expected to be generated as a result of this project. Future steam improvement projects may take advantage of the additional capacity. The maximum steam input will be approximately 153,000 lb/hour of steam at 600 psi and 700 deg F. After completing the installation, the steam header pressure will be controlled by modulating the steam flow to the condensing steam turbine instead of varying the firing rates of the power and bark boilers, which is the current practice. This means that the bark boilers can become based loaded units while firing bark/wood and less fossil fuel will be needed, which is currently fired as necessary to control the steam header pressure.
- No. 1 Power Boiler (EU-002): Oil firing in this boiler will be limited to no more than 820,958 MMBtu per consecutive 12 months (equivalent to 5,623,000 gallons of oil). This is one of the restrictions that allow the

project to avoid PSD preconstruction review for SO_2 emissions. No physical changes are proposed.

- No. 2 Power Boiler (EU-003): This boiler will be prohibited from firing any fuels other than natural gas. This is one of the restrictions that allow the project to avoid PSD preconstruction review for SO_2 emissions. No physical changes are proposed.
- Nos. 1 and 2 Bark Boilers (EU-004 and EU-019): The plant intends to operate each bark boiler approximately 13% more on an annual basis by firing additional purchased bark/wood throughout the year. No physical changes or changes in the method of operation are proposed or necessary to meet this goal.

The applicant identifies the following schedule to construct the project in two phases.

- Phase I: Convert the No. 2 Recovery Boiler and add one new black liquor concentrator. After completing the conversion, operate the BLOX system at a reduced capacity to support only the No. 3 Recovery Boiler. Construction is planned to commence in 2008 and be completed in 2009.
- Phase II: Install one new condensing steam turbine-electrical generator, convert the No. 3 Recovery Boiler, and install a second new black liquor concentrator. Upon startup of the new steam turbine-electrical generator, the Nos. 1 and 2 Bark Boilers will increase operation and the Nos.1 and 2 Power Boilers must begin complying with the oil firing restrictions. Construction is planned to commence in 2008 for the new turbine generator, in 2009 for the No. 3 Recovery Boiler and the second phase completed in 2009.

Originally, the applicant also identified miscellaneous "steam conservation projects" ranging from paper machine steam system improvements to the reclamation of waste heat by using air-to-air heat exchangers. However, in the additional information package dated March 31, 2008, the applicant states that none of these are being proposed as part of the Foley Energy Independence Project. Depending on the scope, timing and potential impacts on emissions from the steam conservation projects, the Department notes that it may be necessary to review and revise the PSD netting analysis provided with the PSD application for the Foley Energy Independence Project because such projects could be within the contemporaneous review period, which is specified in the definition of "net emissions increase" identified in Rule 62-212.400(208), F.A.C. as:

> *(b) An increase or decrease in actual emissions is* ***contemporaneous*** *with the increase from the particular change only if it occurs between:*
>
> *1. The date* ***five years before*** *construction on the particular* ***change commences****; and*
>
> *2. The date that the* ***increase from the particular change occurs****.*

Processing Schedule

12/11/08 Department received an application for an air pollution construction permit subject to PSD review.

04/10/08 Department received additional information requested on 01/10/08.

05/22/08 Department received additional information requested on 05/01/08; application complete.

06/13/08 Department issued initial draft permit package.

06/23/08 Applicant filed a request for an extension of time in which to file a petition.

06/25/08 Applicant provided comments and additional information for consideration.

After consideration of the applicant's comments and additional information, the Department agreed to rescind the initial draft permit package and issue a revised draft permit package.

2. PSD APPLICABILITY REVIEW

General PSD Applicability

The Department regulates major stationary sources of air pollution in accordance with Florida's PSD preconstruction review program pursuant to Rule 62-212.400, F.A.C. A PSD applicability review is required in areas currently in attainment with the state and federal AAQS or areas otherwise designated as "unclassifiable". A facility is considered a major stationary source with respect to PSD if it emits or has the potential to emit: 250 tons per year or more of any regulated air pollutant; 100 tons per year or more of any regulated air pollutant and the facility belongs to one of the 28 PSD major facility categories defined in Rule 62-210.200, F.A.C. for major stationary sources; or 5 tons per year of lead. Projects at existing or new major stationary sources are subject to PSD preconstruction review. In addition, proposed projects at existing minor sources are subject to PSD preconstruction review if potential emissions *from the proposed project* will exceed the PSD major stationary source thresholds.

Once a project becomes subject to PSD preconstruction review, each of the following PSD pollutants is reviewed for PSD applicability based on the "significant emission rates" defined in Rule 62-210.200, F.A.C.: carbon monoxide (CO); nitrogen oxides (NO_X); sulfur dioxide (SO_2); particulate matter (PM); particulate matter with a mean particle diameter of 10 microns or less (PM_{10}); particulate matter with a mean particle diameter of 2.5 microns or less ($PM_{2.5}$); volatile organic compounds (VOC); lead (Pb); Fluorides (Fl); sulfuric acid mist (SAM); hydrogen sulfide (H_2S); total reduced sulfur (TRS), including H_2S; reduced sulfur compounds, including H_2S; municipal waste combustor organics measured as total tetra- through octa-chlorinated dibenzo-p-dioxins and dibenzofurans; municipal waste combustor metals measured as particulate matter; municipal waste combustor acid gases measured as SO_2 and hydrogen chloride (HCl); municipal solid waste landfills emissions measured as nonmethane organic compounds (NMOC); and mercury (Hg). Emissions from the project exceeding the significant emission rate 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 or project may be *major* with respect to PSD for only one regulated pollutant, it may be required to install BACT controls for several "significant" PSD pollutants. Rule 62-210.200, F.A.C. defines "BACT" as:

> *An emission limitation, including a visible emissions standard, based on the maximum degree of reduction of each pollutant emitted which the Department, on a case by case basis, taking into account:*
>
> 1. *Energy, environmental and economic impacts, and other costs;*
> 2. *All scientific, engineering, and technical material and other information available to the Department; and*
> 3. *The emission limiting standards or BACT determinations of Florida and any other state;*
>
> *determines is achievable through application of production processes and available methods, systems and techniques (including fuel cleaning or treatment or innovative fuel combustion techniques) for control of each such pollutant.*
>
> *If the Department determines that technological or economic limitations on the application of measurement methodology to a particular part of an emissions unit or facility would make the imposition of an emission standard infeasible, a design, equipment, work practice, operational standard or combination thereof, may be prescribed instead to satisfy the requirement for the application of BACT. Such standard shall, to the degree possible, set forth the emissions reductions achievable by implementation of such design, equipment, work practice or operation.*
>
> *Each BACT determination shall include applicable test methods or shall provide for determining compliance with the standard(s) by means which achieve equivalent results.*
>
> *In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR Parts 60, 61, and 63.*

In addition, applicants must provide an Air Quality Analysis that evaluates the predicted air quality impacts resulting from the project for each PSD pollutant.

PSD Applicability for Project

The project is located in Taylor County, which is in an area that is currently in attainment with the state and federal AAQS or otherwise designated as unclassifiable. The existing Foley Mill is and existing PSD major stationary source and the project is subject to a PSD applicability review. The equipment efficiency improvements will allow the production of additional steam, which will generate additional energy for use in the plant. However, the project will also allow increased BLS firing rates for the modified recovery boilers and increased annual bark/wood firing rates for the Nos. 1 and 2 Bark Boilers, which will become base-loaded units. The annual fuel oil firing will be restricted in the No. 1 Power Boiler and the No. 2 Power Boiler will be limited to firing only natural gas.

In accordance with Rule 62-212.400(2), F.A.C., the permittee conducted a PSD netting analysis that compared baseline actual emissions with projected actual emissions. The following table summarizes the analysis.

PSD Applicability Summary Provided by Applicant*

Pollutant	Net Emissions Increase	PSD Significant Emissions Rate	Subject to PSD Review?
CO	1715 tons/year	100 tons/year	Yes
NO_X	769 tons/year	40 tons/year	Yes
PM	237 tons/year	25 tons/year	Yes
PM_{10}	183 tons/year	15 tons/year	Yes
$PM_{2.5}$	149 tons/year	N/A	N/A
SAM	4 tons/year	7 tons/year	No
SO_2	35 tons/year	40 tons/year	No
VOC	(-) 57 tons/year	40 tons/year	No
Hg	2 pounds/year	200 pounds/year	No
Pb	37 pounds/year	1200 pounds/year	No
Fl	<< 1ton/year	3 tons/year	No
TRS	(-) 33 tons/year	10 tons/year	No

* *See the additional information provided by the applicant and dated May 21, 2008.*

The above analysis includes contemporaneous emissions increases and decreases from the following projects: Project No. 1230001-017-AC (tall oil project), Project No. 1230001-018-AC (NCG/TRS destruction, a pollution control project) and Project No. 1230001-014-AC (brown stock washer MACT, a pollution control project). Based on the analysis, the project was not subject to PSD preconstruction review for SAM, SO_2, VOC, Hg, Pb, Fl and TRS emissions. However, the project is subject to PSD preconstruction review for CO, NO_X, PM and PM_{10}. The Nos. 2 and 3 Recovery Boilers were the only units being modified or constructed that emit these PSD-significant pollutants. Therefore, the Department must determine the Best Available Control Technology (BACT) for CO, NO_X, PM and PM_{10} emissions from the Nos. 2 and 3 Recovery Boilers. The provisions regulating PM emissions will serve as a surrogate for controlling PM_{10} emissions. In addition, a PSD air quality modeling analysis is required for CO, NO_X and PM/PM_{10} emissions.

3. PSD REVIEW FOR THE NOS. 2 AND 3 RECOVERY BOILERS (EU-006 AND 007)

The Nos. 2 and 3 Recovery Boilers will fire BLS as the primary fuel at maximum firing rates of 97,600 and 82,350 lb/hour of BLS, respectively. For the process, this is also equivalent to 32.45 and 27.45 tons per air-dried unbleached pulp (ADUP). Based on an as-fired heating value of 6400 Btu per lb of BLS, the corresponding maximum heat input rates are 625 and 527 MMBtu per hour. At the new permitted maximum

BLS firing rates, the exhaust flow rate will be approximately 122,849 dscfm @ 8% oxygen and 119,300 dscfm @ 8% oxygen, respectively. There will be no restriction on the hours of operation.

Residual fuel oil containing a maximum sulfur content of 2.5% by weight is fired as a startup and supplemental fuel. The maximum heat input rates from firing oil in the Nos. 2 and 3 Recovery Boilers are 320 and 80 MMBtu per hour. As part of the project, oil firing will be limited to 1,700,000 gallons per year in the No. 2 Recovery Boiler and 2,000,000 gallons per year in the No. 3 Recovery Boiler. Small amounts of on-specification used oil generated on site will be mixed with the residual oil and fired in the boilers. The oil firing rates represent less than 10% of the maximum annual heat input from any fuel.

The recovery boilers will remain subject to all existing state and federal emissions standards. The project is subject to PSD preconstruction review for emissions of CO, NO_X and PM/PM_{10}. For the significant PSD pollutants, the following table summarizes the applicant's estimated potential emissions changes for the boilers due to the project.

Pollutant	Emissions Tons per Year					
	No. 2 Recovery Boiler			No. 3 Recovery Boiler		
	Baseline	Projected Actual	Change	Baseline	Projected Actual	Change
CO	243.6	879.8	+ 636.2	195.8	828.2	+ 632.4
NO_X	245.0	318.8	+ 73.8	207.4	310.0	+ 102.6
PM	73.6	129.4	+ 55.8	33.8	121.7	+ 87.9
PM_{10}	56.5	92.2	+ 35.7	26.0	86.7	+ 60.7

The applicant notes that actual emissions may not increase as a result of the project. Based on these conservative estimates, the project will significantly increase emissions of CO, NO_X and PM/PM_{10}; therefore, BACT determinations are required for these pollutants. Currently, the units are subject to the following standards for these pollutants.

- Rule 62-296.404(1), F.A.C. establishes a standard for visible emissions of 40% opacity (normal operation) except for one period per hour not to exceed 60% opacity.
- Rule 62-296.404(2), F.A.C. establishes a PM standard of 3 lb per 3000 lb of BLS (equivalent to approximately 0.087 grains per dscf @ 8% oxygen.
- NESHAP Subpart MM establishes a PM standard of 0.044 grains per dscf @ 8% oxygen (as a surrogate for reducing metal HAP emissions).

Based on the Title V air operation permit, there are currently no applicable standards for CO or NO_X emissions.

BACT Review for CO Emissions

Discussion

When firing fuels, CO is emitted as a product of incomplete combustion. Uniform and efficient combustion is a function of the three "T's": turbulence (thorough mixing of air and fuel), temperature (sufficient to complete oxidation) and time (adequate to complete combustion at given temperature). A proper furnace design combined with good operating practices that provide a sufficient air-to-fuel ratio can minimize CO emissions.

Applicant's Proposal

The applicant identified the addition of a catalytic oxidation system as the top control option. Exhaust flue gas passes through a section containing specially designed catalyst to complete the oxidation of CO given sufficient temperature. The typical operating temperature range for an oxidation catalyst is between 600° F and 1100° F. Such systems are capable of control efficiencies greater than 90% depending on uncontrolled emission levels and flue gas temperatures. The flue gas temperatures from the recovery boilers will be approximately 350° F, which means large amounts of supplemental fuel must be combusted to maintain the minimum temperature for oxidation. In addition, catalysts are subject to poisoning from metals and blinding from particulate matter. For these reasons, the applicant does not consider the addition of a catalytic oxidation system as a technically feasible option.

The applicant identifies the next available top control option as combustion control. Given the existing furnace design, operators must provide sufficient air and mixing for the fuel being fired to promote efficient combustion. The existing boilers employ an over-fire air (OFA) system that stages combustion air to promote efficient combustion while reducing emissions. Initial combustion air is provided with the fuel in a ratio to produce a reducing flame. Additional combustion air is added in subsequent zones to complete combustion. Analyzers on the boiler exhausts and stacks provide the operators with current oxygen levels. Proper mixing is accomplished by manually adjusting air flow to the oxygen-deficient zone (primary, secondary or tertiary zone). Such adjustments must also consider TRS and NO_X levels, bed height, liquor temperature, etc.

A review of EPA's RACT/BACT/LAER Clearinghouse (RBLC) database identifies CO BACT limits ranging from 200 to 3000 ppmvd depending on the age of the unit, existing furnace design and averaging period for the limit. The BACT determinations are based on combustion control, boiler design and operation, or process controls. For the Nos. 2 and 3 Recovery Boilers, the applicant proposes "boiler design and combustion control" to minimize CO emissions to 400 ppmvd @ 8% oxygen or less (annual average). This is based on the Department's recently established CO BACT determination in Permit No. PSD-FL-380 for Georgia-Pacific's No. 4 Recovery Boiler at the Palatka Mill, which has a 30-day rolling CEMS average. In the application, an upper bound was also identified as 800 ppmvd @ 8% oxygen or less (1-hour average).

Department's Review

The Department identifies thermal and catalytic oxidation as technically feasible control options for reducing CO emissions. The following table summarizes cost information developed from project data and two EPA fact sheets related to thermal and catalytic control options [c, d].

Oxidizer	Capital Cost		Annualized Cost		CO Reductions [b]	Cost Effectiveness
	Factor	Cost [a]	Factor	Cost [a]		
Thermal [c]	\$25-\$90/scfm	\$4.8-\$17.3 million	\$8-\$98/scfm	\$1.5-\$18.8 million	919	\$1632-\$20,457/ton
Catalytic [d]	\$22-\$90/scfm	\$4.2-\$17.3 million	\$8-\$50/scfm	\$1.5-\$9.6 million	891	\$1684-\$10,774/ton

a. The cost estimate assumes a volumetric flow rate of 192,000 scfm @ 33% water vapor.

b. The cost estimate assumes uncontrolled CO emissions of 938 tons/year, a control efficiency of 98% for thermal oxidation and a control efficiency of 95% for catalytic oxidation.

c. Air Pollution Control Technology Fact Sheet: Thermal Incinerator; EPA-452/F-03-022

d. Air Pollution Control Technology Fact Sheet: Catalytic Incinerator; EPA-452/F-03-018

As shown, the capital and operating costs for such systems are substantial. For the recovery boilers, the costs would be near the higher end of the range because of high costs to retrofit the systems, the relatively low uncontrolled CO levels and the low flue gas temperatures, which would result in high supplemental fuel costs. In addition, these estimates are based on full potential emissions. Costs will be much higher if the boiler does not operate full time, operates at partial loads for substantial periods or uncontrolled emissions are lower than expected. Therefore, the Department believes that thermal or catalytic oxidation systems would be cost prohibitive and not appropriate for this project.

The Department accepts the applicant's proposal to minimize CO emissions by boiler design and combustion control with a tertiary OFA system to complete combustion. Based on a review of the available information, the Department establishes the following draft CO BACT standards:

No. 2 Recovery Boiler: As determined by CEMS data, CO emissions shall not exceed 400 ppmvd @ 8% oxygen and 214.1 lb/hour based on a 30-day rolling average that excludes authorized periods of startup and shutdown.

No. 3 Recovery Boiler: As determined by CEMS data, CO emissions shall not exceed 400 ppmvd @ 8% oxygen and 208.0 lb/hour based on a 30-day rolling average that excludes authorized periods of startup and shutdown.

Authorized Periods of Excess CO Emissions: If a 30-day CEMS average shows an exceedance of the CO standards, the permittee may exclude the following amounts of CEMS data to determine compliance: no more than eight hours per startup resulting in high CO emissions; and no more than eight hours per shutdown resulting in high CO emissions.

The new CEMS-based standards require the continuous demonstration of compliance and ensure the use of good operating practices to minimize emissions. The draft standard allows the exclusion of data collected during startup and shutdown because of fluctuations caused by low firing rates, low flue gas flow rates, switching to the primary fuel, etc. In addition, startups and shutdowns for recovery boilers are infrequent with perhaps only a single outage during a given year. No provision to exclude CEMS data during malfunctions is specified because emissions primarily rely on operating practices, which is the justification for the 30-day averaging period. Such incidents should be rare and must be absorbed into the 30-day compliance average.

Although not applicable, the proposed standards are similar to EPA's vacated NESHAP Subpart DDDDD provisions, which were intended to represent complete combustion for new solid fuel-fired boilers. However, the proposed BACT standards do not allow the exclusion of CEMS data collected during periods of operation below 50% of rated capacity as do the Subpart DDDDD provisions. This is to discourage operation at these levels where combustion may be poor. The proposed BACT standards also consider the applicant's design expectations for the modified existing boilers. Based on the applicant's reported annual CO emissions, the recovery boilers will readily comply with the proposed standards.

BACT Review for NO_X Emissions

<u>Discussion</u>

In general, NO_X emissions from recovery boilers are a combination of thermal NO_X and fuel NO_X. Thermal NO_X is produced from a series of chemical reactions in which diatomic nitrogen and oxygen present in the combustion air dissociate in a high temperature combustion zone and react to form NO_X. Fuel NO_X is generated when nitrogen available in the BLS or fuel oil is oxidized to NO_X. However, there may also be many other complex reactions regarding NO_X emissions resulting from the chemical makeup of the flue gas exhaust as well as the furnace and OFA design.

Due to moderate combustion zone temperatures (< 1500° F) and staged combustion techniques, thermal NO_X from a recovery boiler is not believed to be the significant portion of overall NO_X emissions. However, it is possible for higher temperatures in the combustion zone to oxidize more of the available fuel nitrogen to NO_X. In general, NO_X emissions from most recovery boilers are relatively low (< 130 ppmvd) due to moderate furnace temperatures and relatively low nitrogen content of BLS (< 0.20% by weight). For comparison, the nitrogen content of residual oil ranges from 0.2 to 0.5% by weight.

<u>Available Technologies for the Control of NOx Emissions</u>

The following technologies are available for controlling NO_X emissions from recovery boilers.

Selective Catalytic Reduction (SCR): SCR systems work by injecting ammonia into the exhaust gas stream and passing the exhaust across a catalyst bed to further the chemical NO_X reduction reaction. The system converts NO_X to elemental nitrogen (N_2) and water vapor. The optimum temperature range for a conventional SCR catalyst is 550° F to 750° F; however, new catalyst formations are available for temperatures of 1000° F. Potential reductions in NO_X emissions of more than 80% are achievable.

Selective Non-Catalytic Reduction (SNCR): SNCR systems work by injecting ammonia or urea into a high-temperature portion of the furnace or ductwork to convert NO_X to elemental nitrogen and water vapor. The optimum temperature range for an ammonia-based system is 1600° F to 2000° F and for a urea-based system is 1650° F to 2100° F. The reaction must take place within the specified temperature range or it is possible to generate NO_X instead of reducing it. Increasing the residence time available for mass transfer and chemical reactions generally improves NO_X reduction. SNCR systems can reduce NO_X emissions by 50% for industrial boilers and more for utility boilers.

Hybrid SNCR/SCR System: This system consists of over injecting ammonia with an SNCR system and using a small SCR catalyst to react the residual ammonia and NO_X. Such systems may achieve NO_X reductions of more than 80% depending on the application.

Flue Gas Recirculation (FGR): Recirculation of cooler flue gas reduces the combustion temperature by diluting the oxygen content of the combustion air and by causing heat to be diluted by the incoming cooler air. Heat in the flue gas can be recovered by a heat exchanger. This reduction of temperature lowers the thermal NO_X concentration that is generated. Potential reductions in NO_X emissions vary up to 50%.

Overfire Air (OFA): Combustion may be staged by dividing the combustion air with an OFA system to reduce NO_X emissions. Initial combustion air is provided with the fuel in a ratio to produce a reducing flame. Subsequent combustion air is added in more stages to complete combustion of the fuel while maintaining the low temperatures that will prevent thermal NO_X formation. Depending on the applications, OFA systems can reduce NO_X emissions by up to 50%.

Low-NO_X Burners: Low-NO_X burner systems provide a stable flame with several different zones. Typically, the first zone is primary combustion, the second zone is re-burn with fuel added to chemically reduce NO_X, and the third zone is final combustion in low excess air to prevent high temperatures. This technique is available for conventional fuels such as fuel oil and natural gas. Compared to standard burners, NO_X may be reduced by 20% to 50%.

Use of Low-Nitrogen Fuels: This technique involves switching to a fuel with lower nitrogen content to reduce the fuel NO_X emissions. Potential reductions in NO_X emissions are variable.

Applicant's Proposal

The applicant does not believe the following control systems are technically feasible for the recovery boilers.

- *SCR*: Although SCR would be the top available control option, the use of SCR for a recovery furnace has never been demonstrated based on industry documents[1,2] developed by the National Council for Air and Stream Improvement (NCASI). If the SCR reactor is placed before the particulate control device, catalyst plugging and fouling will be a major impediment to effective operation. If the SCR reactor is placed after the particulate control device, the flue gas temperature will be insufficient to support effective NO_X reductions requiring the firing of substantial amounts of supplemental fuel to achieve minimum operating temperatures. In addition, the catalyst material will be subjected to poisoning by alkali metals in the flue gas exhaust. These problems would also result in prohibitive costs.
- *SNCR*: An SNCR system would be the next top available control option. Although there have been successful SNCR tests in Japan and Sweden, no recovery boiler currently operates an SNCR system based on NCASI industry documents[1,2]. There are concerns NO_X-reducing chemicals will have deleterious effects on the Kraft liquor recovery cycle on a long term basis. In addition, the design of recovery furnaces are problematic with temperature fluctuations from load changes, low residence times for small furnaces, tube corrosion and fouling from NO_X-reducing chemicals, and the potential for ammonia slip to form NH_4Cl

1 "Information on Retrofit Control Measures for Kraft Pulp Mill Sources and Boilers for NO_X, SO_2 and PM Emissions"; NCASI CC 06-015; Ronald A. Yeske; June 9, 2006

2 "Effect of Kraft Recovery Furnace Operations on NOx Emissions, a Literature Review and Summary of Industry Experience"; NCASI Special Report No. 03-06; Arun V. Someshwar; 2003

causing plume opacity problems. These problems would also result in prohibitive costs.

- *FGR*: The applicant does not believe that FGR is feasible for a recovery boiler because such systems are used to reduce the contributions of thermal NO_X, which is not the primary NO_X mechanism for a recovery boiler. In addition, the additional flue gas volume would increase velocities and potentially cause greater liquor carryover and result in tube fouling.
- *Use of Low-Nitrogen Fuels*: The nitrogen content of BLS is dependent on the type of wood pulped and is beyond the control of the operators.
- *LNB*: The use of LNB for firing BLS has not been proven. Although LNB for oil firing are technically feasible, the NO_X reductions would be minimal because of the limited amount of oil fired in the recovery boilers.

An OFA system is considered technically feasible. The existing recovery boilers use, or will use, tertiary air systems to stage combustion air and minimize NO_X emissions. To add a quaternary OFA system, the applicant estimated capital costs of approximately \$2.7 million, total annualized costs of approximately \$430,000, and a cost effectiveness of more than \$7000 per ton of NO_X removed based on a 20% reduction from 304 tons/year. The applicant rejected a quaternary OFA system as cost prohibitive.

A review of EPA's RBLC database identifies NO_X BACT limits ranging from 80 to 112 ppmvd @ 8% oxygen based on combustion control, staged combustion, boiler design and operation, and process controls. One entry identifies LNB for the supplemental gas-fired burner. Recently, the Department established a BACT standard of 80 ppmvd @ 8% oxygen in Permit No. PSD-FL-380 for Georgia-Pacific's No. 4 Recovery Boiler at the Palatka Mill. This appears to be the lowest BACT determination for a recovery boiler. Currently, limited test data for the existing Nos. 2 and 3 Recovery Boilers indicates NO_X emissions of only 45 ppmvd @ 8% oxygen. After conversion of the recovery boilers and addition of the concentrators, it is possible that NO_X emissions will increase. However, the applicant believes that the existing OFA systems will be sufficient to achieve a proposed standard of 80 ppmvd @ 8% oxygen for firing BLS in each boiler. However, it may be necessary to install a new tertiary air fan on the No. 3 Recovery Boiler. The applicant also proposes a NO_X standard of 47 lb/1000 gallons for firing fuel oil, which is equivalent to the AP-42 emissions factor.

<u>Department's Review</u>

The Department does not accept the applicant's contention that an SCR system is not technically feasible for recovery boilers. However, the Department acknowledges that it does not appear that this technology has been demonstrated on recovery boilers. The applicant referred to recently issued Permit No. PSD-FL-380 for Georgia-Pacific's No. 4 Recovery Boiler at the Palatka Mill. For that project, cost effectiveness was estimated as \$17,600 per ton of NO_x removed based on actual emissions at the plant and \$10,000 per ton of NO_X removed based on potential NO_X emissions and 90% reduction. Although the Department cannot confirm those cost estimates for this project, it does believe that SCR would be cost prohibitive because of the relatively low uncontrolled NO_X emissions rates as well as high costs associated with retrofitting the existing units.

The Department found only the following reference to employing SNCR on a recovery boiler in Sweden (Sodra Skogsagma), "Demonstrations of SNCR, in addition to municipal waste incinerators and wood- and coal-fueled district heating plant boilers, included a pulp and paper mill Kraft recovery boiler, where a 60% reduction from uncontrolled emissions of 60 ppm was attained.[3]" The Department contacted Fuel-Tech, an SNCR vendor, and discussed the technology for recovery boilers. The vendor could not identify any known installations of SNCR on a recovery boiler, but was aware of the performance test in Sweden. That test was conducted over only a few hours and then the equipment removed. The vendor was not aware of any long term performance tests. Based on the discussions with SNCR vendors, the Department is unable to determine that SNCR is commercially available and demonstrated for recovery boilers at this time.

[3] "White Paper on Selective Non-Catalytic Reduction", Institute of Clean Air Companies, Inc., May 2000

The Department agrees that FGR and LNB would result in substantial costs while providing minimal reductions in thermal NO_X. Although fuel NO_X is the primary contributor, the nitrogen content of BLS is dependent on the type of wood pulped, which is variable. As previously indicated by the applicant, EPA's RBLC shows that previous NO_X BACT determinations have not required add-on control devices, but relied upon combustion control, staged combustion, boiler design and operation, and process controls. Previous NO_X BACT standards have ranged from 70 to 210 ppmvd @ 8% oxygen.

Based on the available information, the Department establishes the following draft NO_X BACT standards:

No. 2 Recovery Boiler: As determined by CEMS data, NO_X emissions shall not exceed 80.0 ppmvd @ 8% oxygen and 70.4 lb/hour based on a 30-day rolling average that excludes authorized periods of startup and shutdown.

No. 3 Recovery Boiler: As determined by CEMS data, NO_X emissions shall not exceed 80.0 ppmvd @ 8% oxygen and 68.3 lb/hour based on a 30-day rolling average that excludes authorized periods of startup and shutdown.

Authorized Periods of Excess NO_X Emissions: If a 30-day CEMS average shows an exceedance of the NO_X standards, the permittee may exclude the following amounts of CEMS data to determine compliance: no more than eight hours per startup resulting in high NO_X emissions; and no more than eight hours per shutdown resulting in high NO_X emissions.

The new CEMS-based standards require the continuous demonstration of compliance and ensure the use of good operating practices to minimize emissions. The draft standard allows the exclusion of data collected during startup and shutdown because of fluctuations caused by low firing rates, low flue gas flow rates, switching to the primary fuel, etc. In addition, startups and shutdowns for recovery boilers are infrequent with perhaps only a single outage during a year. No provision to exclude CEMS data during malfunctions is specified because emissions primarily rely on operating practices, which is the justification for the 30-day averaging period. Such incidents should be rare and must be absorbed into the 30-day compliance average.

BACT Review for PM/PM_{10} Emissions

Discussion

Particulate matter emissions from the recovery boilers are currently controlled by electrostatic precipitators (ESP). The ESP for the No. 2 Recovery Boiler was upgraded in 2003 and now consists of a two-chamber, four-field ESP with a specific collection area of 381 ft^2/1000 acfm. The ESP for the No. 3 Recovery Boiler was upgraded in 1996 and consists of a two-chamber, three-field ESP with a specific collection area of 273 ft^2/1000 acfm. The estimated control efficiency of each unit is 99^+%. The provisions regulating PM emissions will serve as a surrogate for controlling PM_{10} emissions.

Applicant's Proposal

Recovery furnaces are designed and operated to ensure high levels of sodium fumes in order to capture SO_2 produced as a result of oxidizing reduced sulfur compounds. Consequently, uncontrolled particulate matter emissions from recovery boilers are very high, consisting primarily of sodium sulfate with lesser amounts of sodium carbonate and sodium chloride. Removal of these materials is crucial to overall material recovery as it is reused in the process. Similar potassium compounds are generated, but in lower amounts.

Common control equipment for removing particulate matter includes baghouses, ESP and wet scrubbers. Baghouses typically consist of a series of hanging, fine mesh bags and can be designed for removal efficiencies greater than 99%. In general, ESP charge particles for collection on large hanging plates with removal efficiencies greater than 99%. High-energy wet scrubbers (e.g., venturi scrubbers) are effective in removing particulate matter with control efficiencies of 98% or better.

A review of EPA's RBLC database identifies BACT limits ranging from 0.021 to 0.15 grains per dscf for modified recovery boilers. The predominant control device chosen as BACT is the ESP. For comparison purposes, the Department and EPA have promulgated the following standards for existing recovery boilers:

- PM ≤ 3 lb per 3000 lb of BLS (equivalent to approximately 0.087 grains per dscf @ 8% oxygen) pursuant to Rule 62-296.404(2), F.A.C.
- PM ≤ 0.044 grains per dscf @ 8% oxygen pursuant to NSPS Subpart BB; and
- PM ≤ 0.044 grains per dscf @ 8% oxygen (as a surrogate for reducing metal HAP emissions) pursuant to NESHAP Subpart MM.

The applicant selects an ESP as the top control option with a removal efficiency of greater than 99%. As previously mentioned, the ESP for the No. 2 Recovery Boiler was upgraded in 2003 and the ESP for the No. 3 Recovery Boiler was upgraded in 1996. Since these improvements were made, compliance tests have ranged from 0.008 to 0.020 grains/dscf @ 8% oxygen for the No. 2 Recovery Boiler and 0.006 to 0.018 grains/dscf @ 8% oxygen for the No. 3 Recovery Boiler.

Although the project is expected to result in improved combustion, the conversion from a DCE design to low-odor NDCE design may result in increased dust loading to the ESP. Space limitations at this site prevent the installation of additional fields to these units. Therefore, the applicant proposes a BACT standard of 0.030 grains per dscf @ 8% oxygen based on the existing controls. This is equivalent to the PM BACT standard recently established in Permit No. PSD-FL-380 for Georgia-Pacific's No. 4 Recovery Boiler at the Palatka Mill. Also, the applicant requests that the current visible emissions standard be retained, which is 40% opacity (normal operation) except for one period per hour not to exceed 60% opacity as specified by Rule 62-296.404(1), F.A.C. Compliance will be verified by the existing continuous opacity monitoring system (COMS).

Department's Review

The applicant's proposed standard of 0.030 grains per dscf @ 8% oxygen is equivalent to approximately 1.0 lb PM per ton of ADUP. The uncontrolled PM emission factor from Table 10.2-1 in AP-42 is 180 lb per ton of ADUP. So, the estimated control efficiency of the existing electrostatic precipitator would be greater than 99%. The Department agrees that an ESP is a top control system for the recovery boiler process and is frequently the basis of the BACT standards for recovery boilers. Therefore, the Department establishes the following draft BACT standards for particulate matter based on the existing ESP.

- As determined by EPA Method 5, PM emissions from the No. 2 Recovery Boiler shall not exceed 0.030 grains per dscf @ 8% oxygen and 31.6 lb/hour based on the average of three test runs.
- As determined by EPA Method 5, PM emissions from the No. 3 Recovery Boiler shall not exceed 0.030 grains per dscf @ 8% oxygen and 30.7 lb/hour based on the average of three test runs.
- As determined by the existing COMS and/or EPA Method 9, the opacity from each recovery boiler shall not exceed 20% opacity based on 6-minutes averages except for the following periods of startup, shutdown and malfunction.

  a. *Shutdown*: When the Nos. 2 or 3 Recovery Boilers are being shut down for outages, visible emissions shall not exceed 35% opacity based on 6-minute averages as determined by the existing COMS and/or EPA Method 9. Opacity in excess of 35% during shutdowns 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 four hours per shutdown.

  b. *Startup*: When the Nos. 2 or 3 Recovery Boilers are being started up from outages, visible emissions shall not exceed 35% opacity based on 6-minute averages as determined by the existing COMS and/or EPA Method 9. Opacity in excess of 35% during startups 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 four hours per startup.

  c. *ESP Malfunction*: During periods of maintenance to address ESP malfunctions, visible emissions shall not exceed 35% opacity based on 6-minute averages as determined by the existing COMS and/or EPA Method 9. Excess opacity during ESP malfunction repairs 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 four hours in any 24-hour period. This provision applies when it is necessary to shut down a chamber to effect the ESP repair.

The alternate opacity standards and approved periods of excess emissions are based on actual emissions data and procedures currently followed during periods of startup, shutdown and malfunction. Typically, recovery boilers are only shutdown for scheduled maintenance outages or unavoidable equipment failures. This is not only because the recovery process is integral to the operation of the mill, but also because each startup and shutdown requires special procedures to prevent the possibility of equipment explosions. In addition, it is often possible to repair the ESP while minimizing emissions so that the unit does not have to be shutdown. Again, this avoids safety concerns for another startup. Such periods will be infrequent.

The new standards will become effective after completing shakedown of each boiler, but no later than 60 calendar days following first fire after completing the conversion. Compliance with the PM standards shall be demonstrated by conducting initial and annual stack tests. Compliance with the opacity standard shall be demonstrated by a certified COMS and/or EPA Method 9. The permit will also include the following requirements.

Except for infrequent periods of maintenance, all fields of each ESP shall be functioning when the boiler is in operation. Based on satisfactory tests demonstrating compliance with the PM and opacity standards of this permit, each ESP may operate with a field removed from service to facilitate maintenance on that field. Such periods of maintenance that do not create excess opacity shall be corrected as soon as practicable.

Separate tests shall be conducted while operating with all fields in service and with one field removed from service.

Operational Restrictions

In addition to specifying the new permitted capacities and firing rates, the permit will establish conditions with the following oil firing restrictions:

- The No. 2 Recovery Boiler shall not fire more than 1,700,000 gallons of oil during any consecutive 12-month rolling total.
- The No. 3 Recovery Boiler shall not fire more than 2,000,000 gallons of oil during any consecutive 12-month rolling total.

The oil firing restrictions were requested by the applicant to reflect the actual maximum expected firing capacities for residual oil, which is a startup and supplemental fuel for the recovery boilers. Although the application identified tall oil as an existing authorized fuel, the original air construction permit has expired and tall oil is included in the Title V air operation permit. The applicant is processing a separate request with the Northeast District Office to add tall oil as an authorized fuel.

4. OTHER PERMITTING ISSUES

This section identifies other primary conditions specified in the draft permit.

Construction Schedule

The permittee identifies the following preliminary schedule to construct the project in two phases.

- Phase I: Convert the No. 2 Recovery Boiler and add one new black liquor concentrator. After completing the conversion, the BLOX system will be operated at a reduced capacity to support only the No. 3 Recovery Boiler. Construction is planned to commence in 2009 and be completed in 2009.
- Phase II: Install one new condensing steam turbine-electrical generator, convert the No. 3 Recovery Boiler, and install a second new black liquor concentrator. Upon startup of the new steam turbine-electrical generator, the Nos. 1 and 2 Bark Boilers will increase operation and the Nos. 1 and 2 Power Boilers must

begin complying with the oil firing restrictions. Construction is planned to commence in 2009 for the new turbine generator, in 2009 for the No. 3 Recovery Boiler and the second phase completed in 2010.

- If these preliminary plans change, the permittee shall submit a revised construction schedule to the Compliance Authority.

BLOX System

After completing the No. 2 Recovery Boiler conversion, the maximum throughput of the black liquor oxidation (BLOX) system will be reduced by approximately 54% to support only the No. 3 Recovery Boiler. After completing the No. 3 Recovery Boiler conversion, the BLOX system shall be permanently shutdown.

New Condensing Steam Turbine-Electrical Generator

The plant currently operates four extraction steam turbine-electrical generators with a total capacity of 39 MW. The permittee is authorized to install a new 28 MW condensing steam turbine-electrical generator to take advantage of the equipment efficiency improvements and additional bark/wood firing. The maximum steam input will be approximately 153,000 lb/hour of steam at 600 psi and 700° F. After completing the installation, the steam header pressure will be controlled by modulating the steam flow to the condensing steam turbine instead of varying the firing rates of the power and bark boilers, which is the current practice.

No. 1 Power Boiler (EU-002)

After completing installation of the new 28 MW condensing steam turbine-electrical generator, the No. 1 Power Boiler shall fire no more than 5,623,000 gallons of oil during any consecutive 12-month rolling average. The permittee shall keep records sufficient to determine compliance with this requirement. This amount of oil represents an annual capacity factor of approximately 38% and is an acknowledgement that this unit will be operated less and the bark boilers more.

No. 2 Power Boiler (EU-003)

After completing installation of the new 28 MW condensing steam turbine-electrical generator, the No. 2 Power Boiler shall fire only natural gas. This is one of the restrictions that allow the project to avoid PSD preconstruction review for SO_2 emissions. The permittee shall keep records sufficient to determine compliance with this requirement.

Annual Emissions Reporting

This permit is based on an analysis that compared baseline actual emissions with projected actual emissions and avoided the requirements of subsection 62-212.400(4) through (12), F.A.C. for several pollutants. Pursuant to Rule 62-212.300(1)(e), F.A.C., the applicant is required submit reports characterizing the actual emissions for a period of five years after completing the project.

5. AIR QUALITY ANALYSIS

This section provides a general overview of the modeling analyses required for PSD preconstruction review followed by the specific analyses required for this project.

Overview of the Required Modeling Analyses

Pursuant to Rule 62-212.400, F.A.C., the applicant is required to conduct the following analyses for each PSD significant pollutant:

- A preconstruction ambient air quality analysis,
- A source impact analysis based on EPA-approved models, and
- An additional impact analyses.

For the purposes of any required analysis, NO_X emissions will be modeled as NO_2 and only PM_{10} emissions will be considered when modeling particulate matter.

Preconstruction Ambient Monitoring Analysis

Generally, the first step is to determine whether the Department will require preconstruction ambient air quality monitoring. Using an EPA-approved air quality model, the applicant must determine the predicted maximum ambient concentrations and compare the results with regulatory thresholds for preconstruction ambient monitoring, known as de minimis air quality levels. The regulations establish de minimis air quality levels for several PSD pollutants as shown in the following table. For ozone, there is no de minimis air quality level because it is not emitted directly. However, since NO_2 and VOC are considered precursors for ozone formation, the applicant may be required to perform an ambient impact analysis (including the gathering of ambient air quality data) for any net increase of 100 tons per year or more of NO_2 or VOC emissions.

If the predicted maximum ambient concentration is less than the corresponding de minimis air quality level, Rule 62-212.400(3)(e), F.A.C. exempts that pollutant from the preconstruction ambient monitoring analysis. If the predicted maximum ambient concentration is more than the corresponding de minimis air quality level (except for non-methane hydrocarbons), the applicant must provide an analysis of representative ambient air concentrations (pre-construction monitoring data) in the area of the project based on continuous air quality monitoring data for each such pollutant with an Ambient Air Quality Standard (AAQS). If no such standard exists, the analysis shall contain such air quality monitoring data as the Department determines is necessary to assess ambient air quality for that pollutant.

PSD Pollutant	De Minimis Air Quality Levels
CO	575 μg/m3, 8-hour average
NO_2	14 μg/m3, annual average;
PM_{10}	10 μg/m3, 24-hour average
SO_2	13 μg/m3, 24-hour average
Pb	0.1 μg/m3, 3-month average
Fl	0.25 μg/m3, 24-hour average
TRS	10 μg/m3, 1-hour average
H_2S	0.2 μg/m3, 1-hour average
RSC	10 μg/m3, 1-hour average
Hg	0.25 μg/m3, 24-hour average

If preconstruction monitoring data is necessary, the Department may require the applicant to collect representative ambient monitoring data in specified locations prior to commencing construction on the project. Alternatively, the Department may allow the requirement for preconstruction monitoring data to be satisfied with data collected from the Department's extensive ambient monitoring network. Preconstruction monitoring data must meet the requirements of Appendix B to 40 CFR 58 during the operation of the monitoring stations. The preconstruction monitoring data will be used to determine the appropriate ambient background concentrations to support any required AAQS analysis.

Finally, after completing the project, the Department may require the applicant to conduct post-construction ambient monitoring to evaluate actual impacts from the project on air quality.

Source Impact Analysis

For each PSD-significant pollutant identified above, the applicant is required to conduct a source impact analysis for affected PSD Class I and Class II areas. This analysis is to determine if emissions from this project will significantly impact levels established for Class I and II areas. Class I areas include protected federal parks and national wilderness areas (NWA) that are under the protection of federal land managers. The table identifies the Class I areas located in Florida or that are within 200 kilometers in nearby states. Class II areas represent all other areas in the vicinity of the facility open to public access that are not Class I areas.

Class I Area	State	Federal Land Manger
Bradwell Bay NWA	Florida	U.S. Forest Service
Chassahowitzka NWA	Florida	U.S. Fish and Wildlife Service
Everglades National Park	Florida	National Park Service
Okefenokee NWA	Georgia	U.S. Fish and Wildlife Service
St. Marks NWA	Florida	U.S. Fish and Wildlife Service
Wolf Island NWA	Georgia	U.S. Fish and Wildlife Service

An initial significant impact analysis is conducted using the worst-case emissions scenario for each pollutant and corresponding averaging time. The regulations define separate significant impact levels for Class I and Class II areas for CO, NO_2, Pb, PM_{10} and SO_2. Based on the initial significant impact analysis, no additional modeling is required for any pollutant with a predicted ambient concentration less than the corresponding significant impact level. However, for any pollutant with a predicted ambient concentration exceeding the corresponding significant impact level, the applicant must conduct a full impact analysis. In addition to evaluating impacts caused by the project, a full impact modeling analysis also includes impacts from other nearby major sources (and any potentially-impacting minor sources within the radius of significant impact) as well to determine compliance with:

- The PSD increments and the federal air quality related values (AQRV) for Class I areas.
- The PSD increments and the AAQS for Class II areas.

As previously mentioned, for any net increase of 100 tons per year or more of VOC or NO_2 subject to PSD, the applicant may be required to perform an ambient impact analysis for ozone including the gathering of ambient ozone data.

PSD Class I Area Model

The California Puff (CALPUFF) dispersion model is used to evaluate the potential impacts on PSD Class I increments, the federal land manager's Air Quality Related Values (AQRV) for regional haze as well as nitrogen and sulfur deposition. The CALPUFF model is a non-steady state, Lagrangian, long-range transport model that incorporates Gaussian puff dispersion algorithms. This model determines ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, line, area and volume sources. The CALPUFF model has the capability to treat time-varying sources. It is also suitable for modeling domains from tens of meters to hundreds of kilometers and has mechanisms to handle rough or complex terrain situations. Finally, the CALPUFF model is applicable for inert pollutants as well as pollutants that are subject to linear removal and chemical conversion mechanisms.

The meteorological data used in the CALPUFF model is processed by the California Meteorological (CALMET) model. Data from multiple meteorological stations is processed by the CALMET model to produce a three-dimensional modeling grid domain of hourly temperature and wind fields. The wind field is enhanced by the use of terrain data, which is also input into the model. Two-dimensional fields such as mixing heights, dispersion properties and surface characteristics are produced by the CALMET model as well.

PSD Class II Area Model

The EPA-approved American Meteorological Society and EPA Regulatory Model (AERMOD) dispersion model is used to evaluate short range impacts from the proposed project and other existing major sources. In November of 2005, the EPA promulgated AERMOD as the preferred regulatory model for predicting pollutant concentrations within 50 kilometers of a source. The AERMOD model is a replacement for the Industrial Source Complex Short-Term model (ISCST3). The AERMOD model calculates hourly concentrations based on hourly meteorological data. The model can predict pollutant concentrations for annual, 24-hour, 8-hour, 3-hour and 1-hour averaging periods. In addition to the PSD Class II modeling, it is also used to model the predicted impacts for comparison with the de minimis ambient air quality levels when determining preconstruction monitoring requirements.

For evaluating plume behavior within the building wake of structures, the AERMOD model incorporates the Plume Rise Enhancement (PRIME) downwash algorithm developed by the Electric Power Research Institute (EPRI). A series of specific model features recommended by the EPA are referred to as the regulatory options. The applicant used the EPA-recommended regulatory options in each modeling scenario and building downwash effects were evaluated for stacks below the good engineering practice (GEP) stack heights.

Stack Height Considerations

GEP stack height means the greater of 65 meters (213 feet) or the maximum nearby building height plus 1.5 times the building height or width, whichever is less. Where the affected stacks did not meet the requirements for GEP stack height, building downwash was considered in the modeling analyses. Based on a review of this application, the Department determines that the project complies with the applicable provisions of the stack height regulations as revised by EPA on July 8, 1985 (50 FR 27892). Portions of the regulations have been remanded by a panel of the U.S. Court of Appeals for the D.C. Circuit in NRDC v. Thomas, 838 F. 2d 1224 (D.C. Cir. 1988). Consequently, this permit may be subject to modification if and when EPA revises the regulation in response to the court decision. This may result in revised emission limitations or may affect other actions taken by the source owners or operators.

Additional Impact Analysis

In addition to the above analyses, the applicant must provide an evaluation of impacts to: soils, vegetation, and wildlife; air quality related to general commercial, residential and industrial growth in the area that may result from the project; and regional haze in the affected Class I areas.

PSD Significant Pollutants for the Project

As discussed previously, the proposed project will increase emissions of the following pollutants in excess of the PSD significant emissions rates: CO, NO_X and PM/PM_{10}. For the purposes of any required analysis, NO_X emissions will be modeled as NO_2 and only PM_{10} emissions will be considered when modeling particulate matter.

Preconstruction Ambient Monitoring Analysis

Using the AERMOD model, the applicant predicted the following maximum ambient impacts from the project. The applicant's receptor grid extended out to 7 kilometers (km) from the facility and included over 3800 receptors.

De Minimis Air Quality Levels				
Pollutant	Averaging Time	Maximum Predicted Impact ($\mu g/m^3$)	De Minimis Concentration ($\mu g/m^3$)	Greater than De Minimis?
CO	8-hour	29	575	No
NO_2	Annual	1.6	14	No
PM_{10}	24-hour	4.5	10	No

As shown above, CO, NO_2 and PM_{10} are exempt from preconstruction monitoring because the predicted impacts are less than the de minimis levels. However, the project results in PSD net emissions increases of greater than 700 tons/year of NO_x, which is above the threshold of 100 tons/year that requires an ambient impact analysis including the gathering of ambient air quality data. Nevertheless, the Department maintains an extensive quality-assured ambient monitoring network throughout the state. The following table summarizes ambient data from 2004 to 2007 available for existing nearby monitoring locations for NO_2 and Ozone.

Representative Ambient Concentrations			
Pollutant	Averaging Time	Ambient Concentration	Monitor Location
NO_2	Annual	26 ppbv	Jacksonville
Ozone	8-hour	67 ppbv	Leon County

The existing monitoring data show no violations of any ambient air quality standards. The Department determines that the data collected from these monitors is representative of the air quality in the vicinity of the project and may be used to satisfy the preconstruction monitoring requirements for NO_2. As necessary, the above ambient concentrations will be used as the ambient background concentrations for any required AAQS analysis.

In addition, the applicant and the Department discussed available options for potentially predicting ambient ozone impacts caused by the NO_2 emissions increases (ozone precursor pollutant) from the project. No stationary point source models are available or approved for use in predicting ozone impacts. Although regional models exist for predicting ambient ozone levels, it is unlikely that impacts caused by this project could be adequately evaluated because it is so small compared to regional effects. The Department determines that the use of a regional model incorporating the complex chemical mechanisms for predicting ozone formation is not appropriate for this project. No further modeling is required for ozone impacts.

Source Impact Analysis for PSD Class I Areas

Affected PSD Class I Areas

For PSD Class I areas within 200 km of the facility, the table identifies each affected Class I area as well as the distance to the facility and the number of receptors used in the modeling analysis. Since each of these areas contains receptors greater than 50 km from the proposed facility, long-range transport modeling was required for the PSD Class I impact assessment. However, there is a portion of the St. Marks NWA that is less than 50 km from the facility. For this portion, AERMOD was used.

PSD Class I Area	Distance	Receptors
Bradwell Bay NWA	95 km	132
Chassahowitzka NWA	163 km	113
St. Marks NWA	41 km	101
Okefenokee NWA	116 km	500

Meteorological Data for PSD Class I Analysis

Meteorological data from 2001 through 2003 for a 4-km Florida domain were obtained and processed for use in the PSD Class I analyses. The CALMET wind field and the CALPUFF model options used were consistent with the guidance from the federal land managers.

Results of PSD Class I Significant Impact Analysis

Using the CALPUFF model, the applicant predicted the following maximum ambient impacts from the project.

Significant Impact Analysis for PSD Class I Areas					
Pollutant	**Averaging Time**	**Maximum Predicted Impact (μg/m^3)**	**Significant Impact Level (μg/m^3)**	**Significant Impact?**	**Affected Class I Area**
NO_2	Annual	0.03	0.1	No	St. Marks NWA
PM_{10}	Annual	0.01	0.2	No	St. Marks NWA
	24-hour	0.20	0.3	No	St. Marks NWA

As shown, the maximum predicted impacts are less than the corresponding significant impact levels for each pollutant. AERMOD impacts for the portion of St. Marks NWA were less than the CALPUFF impacts. Therefore, a full impact analysis for the PSD Class I areas is not required.

Source Impact Analysis for PSD Class II Areas

Meteorological Data for PSD Class II Analysis

Meteorological data used in the AERMOD model consisted of a concurrent five-year period of hourly surface weather observations and twice-daily upper air soundings from the Tallahassee Regional Airport. The five-year period of meteorological data was from 2001 through 2005. These stations were selected for use in the evaluation because they are the closest primary weather stations to the project area and are most representative of the project site.

The applicant used over 2000 receptors along the fenced property boundary and out to 4 km for this analysis.

For the preliminary significant impact analysis, the highest short-term predicted concentrations will be compared to the respective significant impact levels. Since five years of data are available, the highest-second-high (HSH) short-term predicted concentrations will be used for any required AAQS and PSD Class II increment analysis with regard to short-term averages. However, for annual averages, the highest predicted annual average will be compared with the corresponding annual level.

Results of the Significant Impact Analysis

The following table shows the results of the preliminary PSD Class II significant impact analysis.

Significant Impact Analysis for PSD Class II Areas (Vicinity of Facility)					
Pollutant	**Averaging Time**	**Maximum Predicted Impact ($\mu g/m^3$)**	**Significant Impact Level ($\mu g/m^3$)**	**Significant Impact?**	**Radius of Significant Impact (km)**
CO	8-hr	29	500	No	None
	1-hr	38	2,000	No	None
NO_2	Annual	1.6	1	Yes	2
PM_{10}	Annual	0.7	1	No	None
	24-hr	4.5	5	No	None

As shown above, the predicted impacts of CO and PM_{10} are below the corresponding PSD Class II significant impact levels and no further analysis is required. The predicted impacts of NO_2 are greater than the corresponding PSD Class II significant impact levels; therefore, a full impact analysis for this pollutant is required within the applicable significant impact area as defined by the predicted radius of significant impact identified above. For NO_2 emissions, a PSD Class II increment analysis and an AAQS analysis must be conducted.

Receptor Grids for Performing PSD Increments and AAQS Analyses

For the PSD Class II increment and AAQS analyses, receptor grids are normally based on the size of the significant impact area for each pollutant. As shown in the previous section, the predicted radius of significant impact for NO_2 was 2 kilometers. For these analyses, however, the applicant retained the original grid containing over 2000 receptors out to 4 kilometers from the facility.

PSD Class II Increment Analysis

The PSD increment represents the amount that new sources in an area may increase ambient ground level concentrations of a pollutant from a regulatory baseline concentration. For PM_{10} and SO_2, the baseline concentrations were established in 1977 with a baseline year of 1975 for existing major sources. For NO_2, the baseline concentration was established in 1988 with a baseline year of 1988 for existing major sources. The emission values input into the model for predicting increment consumption are based on the maximum emissions rates from increment-consuming sources at the facility as well as all other increment-consuming sources in the vicinity of the facility. The preliminary analysis indicated NO_2 to be significant for this project. The following table summarizes the results of the PSD Class II increment analysis.

PSD Class II Increment Analysis				
Pollutant	**Averaging Time**	**Maximum Predicted Impacts ($\mu g/m^3$)**	**Allowable Increment ($\mu g/m^3$)**	**Greater than PSD Class II Allowable Increment?**
NO_2	Annual	1.3	25	No

As shown above, the maximum predicted impacts are less than the allowable PSD Class II increments.

AAQS Analysis

For each pollutant subject to an AAQS analysis, the total impact on ambient air quality is obtained by adding an ambient background concentration to the maximum predicted concentration from modeled sources. The ambient background concentration accounts for all sources that are not explicitly modeled. The following table summarizes the results of the AAQS analysis for the affected pollutants.

AAQS Analysis						
Pollutant	Averaging Time	Modeled Sources ($\mu g/m^3$)	Ambient Background Concentration ($\mu g/m^3$)	Total Impact ($\mu g/m^3$)	AAQS ($\mu g/m^3$)	Greater than AAQS?
NO_2	Annual	4.3	26.2	30.5	100	No

As shown in this table, impacts from the proposed project are not expected to cause or significantly contribute to a violation of any AAQS.

Additional Impacts Analysis

Impacts on Soils, Vegetation and Wildlife

The maximum predicted ground-level concentrations of CO, NO_2 and PM_{10} from the proposed project and all other nearby sources are below the corresponding AAQS. The AAQS are designed to protect both the public health and welfare. As such, this project is not expected to have a harmful impact on soils, vegetation or wildlife in the vicinity of the project.

Air Quality Impacts Related to Growth

The proposed modification will not significantly change employment, population, housing, commercial development, or industrial development in the area to the extent that a significant air quality impact will result.

Regional Haze Analysis

The applicant conducted an AQRV analysis for the Class I areas. No significant impacts on these areas are expected. A regional haze analysis using the long-range transport model CALPUFF was conducted for the PSD Class I areas. The regional haze analysis showed no significant impact on visibility in these areas. Total nitrogen deposition rates on the PSD Class I areas were also predicted using CALPUFF. The applicant submitted supplementary modeling results that showed impacts that were barely over the deposition analysis threshold (DAT). This threshold is extremely conservative. The air quality dispersion modeler for the U.S. Fish and Wildlife Service and the manager of the St. Marks NWA Refuge both concur that there will be no significant impacts to the St. Marks Class I area because of the project.

Conclusion on Air Quality Impacts

As described in this report and based on the applicant's ambient impact analyses, the Department has reasonable assurance that the proposed project will not cause, or significantly contribute to, a violation of any AAQS or PSD increment.

6. 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. Bruce Mitchell is the project engineer responsible for reviewing the application and drafting the permit conditions. Cleve Holladay is the meteorologist responsible for reviewing and approving the ambient air quality analyses. 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.

REVISED DRAFT PERMIT

PERMITTEE

Buckeye Florida, Limited Partnership
One Buckeye Drive
Perry, Florida 32348

Authorized Representative:
Mr. Howard Drew, Vice President

Air Permit No. PSD-FL-397
Project No. 1230001-023-AC
Permit Expires: November 1, 2011
Buckeye Foley Mill
Facility ID No. 1230001
Foley Energy Independence Project

FACILITY AND LOCATION

Buckeye Florida, Limited Partnership operates the existing Foley Mill, which is a dissolving grade Kraft process pulp mill (SIC No. 2611) located in Taylor County at One Buckeye Drive in Perry, Florida. The map coordinates of this facility are: Zone 17; 256.7 km East; and, 3328.7 km North. This permit authorizes the following work: conversion of the Nos. 2 and 3 Recovery Boilers from direct contact evaporator units to low-odor, non-direct contact evaporator units; permanent shutdown of the black liquor oxidation system once conversion of the recovery boilers is complete; addition of two new forced-circulation/crystallizer black liquor concentrators and a black liquor storage tank to the existing multiple effect evaporator system; installation of a new 28 megawatt condensing steam turbine-electrical generator set; and miscellaneous common system changes including piping, ductwork, pumps, tanks, etc.

STATEMENT OF BASIS

This air pollution construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), and Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.). The permittee is authorized to conduct the proposed work in accordance with the conditions of this permit and as described in the application. This project is subject to the general preconstruction review requirements in Rule 62-212.300, F.A.C. as well as the preconstruction review requirements for major stationary sources in Rule 62-212.400, F.A.C. for the Prevention of Significant Deterioration (PSD) of Air Quality.

CONTENTS

(DRAFT)

Joseph Kahn, Director
Division of Air Resource Management

Effective Date

FACILITY DESCRIPTION

Buckeye Florida, Limited Partnership operates an existing dissolving grade Kraft process pulp mill in Perry, Florida. In the Kraft process, the digesting liquor (white liquor) is a solution of sodium hydroxide and sodium sulfide that is mixed with wood chips and cooked under pressure. The spent liquor, known as weak black liquor, is concentrated and sodium sulfate is added to make up for chemical losses. The black liquor solids (BLS) are burned in the recovery furnaces to produce a smelt of sodium carbonate and sodium sulfide. The smelt is dissolved in water to form green liquor to which quicklime (calcium oxide) is added to convert the sodium carbonate back to sodium hydroxide, which reconstitutes the cooking liquor. The spent lime cake (calcium carbonate) is recalcined in a rotary lime kiln to produce quicklime, which is used to convert the green liquor to cooking liquor. Steam and energy needs at the plant are met by: combination boilers, which burn bark/wood and supplemental residual oil; power boilers, which burn residual oil and natural gas; and recovery boilers, which burn BLS and supplemental residual oil.

FACILITY REGULATORY CLASSIFICATION

- The facility is a major source of hazardous air pollutants (HAP).
- The facility has no units subject to the acid rain provisions of the Clean Air Act.
- The facility is a Title V major source of air pollution in accordance with Chapter 213, F.A.C.
- The facility is a major stationary source in accordance with Rule 62-212.400(PSD), F.A.C.

PROJECT DESCRIPTION

The goal of the Foley Energy Independence Project is to improve efficiency for steam and electrical equipment at the plant, reduce the amount of electricity purchased from the grid and reduce the amount of purchased fossil fuels. Currently, the mill purchases approximately 120,000 MW-hours per year of electricity and approximately 6 million MMBtu per year of fossil fuels. The project consists of the following major changes.

- The existing Nos. 2 and 3 Recovery Boilers (EU-006 and EU-007) will be physically modified and converted from direct contact evaporator units to low-odor, non-direct contact evaporator units. The changes will promote more efficient firing of black liquor. After completing the No. 2 Recovery Boiler conversion, operation of the black liquor oxidation system will be reduced to support only the No. 3 Recovery Boiler. After completing the No. 3 Recovery Boiler conversion, the black liquor oxidation system will be permanently shutdown. Oil firing for each unit will be restricted to annual capacity factors of much less than 10% based on the corresponding total maximum annual heat input rates.
- Two new forced-circulation/crystallizer black liquor concentrators and a new black liquor storage tank will be added to the existing multiple effect evaporator system (EU-046). The new concentrators will increase the solids content of the BLS from approximately 50% to 72%. Increased non-condensable gases generated from the multiple effect evaporator system will be controlled by combustion in the No. 1 Bark Boiler (primary control) or the No. 1 Power Boiler (secondary control), which also controls TRS emissions with a white liquor pre-scrubber.
- There will be miscellaneous changes to the common systems shared by the existing units such as piping, ductwork, pumps, tanks, etc.
- The plant currently operates four extraction steam turbine-electrical generators with a total capacity of 39 MW. A new 28 MW condensing steam turbine-electrical generator will be installed to take advantage of the equipment efficiency improvements and approximately 13% additional bark/wood firing (annual basis) in the Nos. 1 and 2 Bark Boilers. Only 12 MW are expected to be generated as a result of this project. Future steam improvement projects may take advantage of the additional capacity. No physical changes or changes

in the method of operation for the Bark Boilers are necessary to meet this goal. After completing the installation, the steam header pressure will then be controlled by modulating the steam flow to the condensing steam turbine instead of varying the firing rates of the power and bark boilers, which is the current practice. This means that the Bark Boilers can become based loaded units while firing bark/wood and less fossil fuel will be needed, which is currently fired as necessary to control the steam header pressure.

- Based on the equipment efficiency improvements and shift to bark/wood, less fossil fuel oil will be fired. The maximum fossil fuel oil firing rate for the No. 1 Power Boiler (EU-002) will be reduced to an annual capacity factor of approximately 38% and only natural gas will be fired in the No. 2 Power Boiler (EU-003). No other changes are proposed for these units.

The project will be constructed in two phases according to the following preliminary schedule.

Phase I: Convert the No. 2 Recovery Boiler and add one new black liquor concentrator. After completing the conversion, reduce operation of the black liquor oxidation system to support only the No. 3 Recovery Boiler. Construction is planned to commence and be completed in 2009.

Phase II: Install one new condensing steam turbine-electrical generator, convert the No. 3 Recovery Boiler, and install a second new black liquor concentrator. Upon startup of the new steam turbine-electrical generator, the Nos. 1 and 2 Bark Boilers will increase operation and the Nos. 1 and 2 Power Boilers must begin complying with the oil firing restrictions. Construction is planned to commence and be completed in 2010.

AFFECTED EMISSIONS UNITS

This project affects the following existing emissions units and activities.

ID	Emission Unit Description
002	No. 1 Power Boiler
003	No. 2 Power Boiler
004	No. 1 Bark Boiler
006	No. 2 Recovery Boiler
007	No. 3 Recovery Boiler
019	No. 2 Bark Boiler
046	Pulping and Multiple Effect Evaporator Systems
N/A	Black Liquor Oxidation System
N/A	28 MW Condensing Steam Turbine-Electrical Generator

PSD APPLICABILITY

In accordance with Rule 62-212.400(2), F.A.C., the permittee conducted a PSD netting analysis that compared baseline actual emissions with projected actual emissions. Based on the analysis, the project was not subject to PSD preconstruction review for sulfur dioxide (SO_2), sulfuric acid mist (SAM), volatile organic compounds (VOC), and total reduced sulfur (TRS). However, the project is subject to PSD preconstruction review for carbon monoxide (CO), nitrogen oxides (NO_X), particulate matter (PM), and PM with an aerodynamic diameter equal to or less than 10 microns (PM_{10}). The Nos. 2 and 3 Recovery Boilers were the only units being modified or constructed that emit the PSD-significant pollutants. Therefore, the Department determined the Best Available Control Technology (BACT) for CO, NO_X, PM and PM_{10} emissions from the Nos. 2 and 3 Recovery Boilers. The provisions regulating PM emissions will serve as a surrogate for controlling PM_{10} emissions.

1. Permitting Authority: The Permitting Authority for this project is the Bureau of Air Regulation in the Division of Air Resource Management of the Department. The mailing address is 2600 Blair Stone Road, MS #5505, Tallahassee, Florida 32399-2400. The phone number is 850/488-0114.

2. Compliance Authority: All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Air Resource Section of the Department's Northeast District Office. The mailing address is 7825 Baymeadows Way, Suite 200B, Jacksonville, Florida, 32256. The phone number is 904/807-3300.

3. Appendices: The following Appendices are attached as an enforceable part of this permit unless otherwise indicated: Appendix A (Citation Formats), Appendix B (General Conditions), Appendix C (Common Conditions), Appendix D (Standard Testing Requirements), Appendix E (Final BACT Determinations), Appendix F (Standard Continuous Emissions Monitoring Requirements) and Appendix G (On-Specification Used Oil Requirements).

4. Applicable Regulations, Forms and Application Procedures: Unless otherwise specified in this permit, the construction and operation of the subject emissions units shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of: Chapter 403, F.S.; and Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-296, and 62-297, F.A.C. Issuance of this permit does not relieve the permittee from compliance with any applicable federal, state, or local permitting or regulations.

5. New or Additional Conditions: For good cause shown and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions, and on application of the permittee, the Department may grant additional time. [Rule 62-4.080, F.A.C.]

6. Modifications: No emissions unit shall be constructed or modified without obtaining an air construction permit from the Department. Such permit shall be obtained prior to beginning construction or modification. [Rules 62-210.300(1) and 62-212.300(1)(a), F.A.C.]

7. Source Obligation:

   (a) Authorization to construct shall expire if construction is not commenced within 18 months after receipt of the permit, if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. This provision does not apply to the time period between construction of the approved phases of a phased construction project except that each phase must commence construction within 18 months of the commencement date established by the Department in the permit.

   (b) At such time that a particular source or modification becomes a major stationary source or major modification (as these terms were defined at the time the source obtained the enforceable limitation) solely by virtue of a relaxation in any enforceable limitation which was established after August 7, 1980, on the capacity of the source or modification otherwise to emit a pollutant, such as a restriction on hours of operation, then the requirements of subsections 62-212.400(4) through (12), F.A.C., shall apply to the source or modification as though construction had not yet commenced on the source or modification.

   (c) At such time that a particular source or modification becomes a major stationary source or major modification (as these terms were defined at the time the source obtained the enforceable limitation) solely by exceeding its projected actual emissions, then the requirements of subsections 62-212.400(4) through (12), F.A.C., shall apply to the source or modification as though construction had not yet commenced on the source or modification.

   [Rule 62-212.400(12), F.A.C.]

8. Title V Permit: This permit authorizes specific modifications and/or new construction on the affected emissions units as well as initial operation to determine compliance with conditions of this permit. A Title V operation permit is required for regular operation of the permitted emissions units. The permittee shall apply for a Title V operation permit at least 90 days prior to expiration of this permit, but no later than 180 days after completing the required work and commencing operation. To apply for a Title V operation permit, the applicant shall submit the appropriate application form, compliance test results, and such additional information as the Department may by law require. The application shall be submitted to the Air Resource Section of the Department's Northeast District Office. [Rules 62-4.030, 62-4.050, 62-4.220, and Chapter 62-213, F.A.C.]

9. Previous Air Construction Permits: This permit supplements all previous permits issued for the affected emissions units. The conditions of this permit satisfy the applicable requirements for the emissions increases related to the project. These conditions supersede corresponding similar conditions specified in previous air construction permits. However, if not specifically regulated by this permit, other standards and permit requirements from previous air construction permits remain valid. [Rules 62-212.300 and 62-212.400(BACT), F.A.C.]

10. Construction Schedule: The following summarizes the preliminary construction schedule for the project.

    a. *Phase I*: Convert the No. 2 Recovery Boiler and add one new black liquor concentrator. After completing the conversion, reduce operation of the black liquor oxidation system to support only the No. 3 Recovery Boiler. Construction is planned to commence and be completed in 2009.

    b. *Phase II*: Install one new condensing steam turbine-electrical generator, convert the No. 3 Recovery Boiler, and install a second new black liquor concentrator. Upon startup of the new steam turbine-electrical generator, the Nos. 1 and 2 Bark Boilers will increase operation and the Nos. 1 and 2 Power Boilers must begin complying with the oil firing restrictions. Construction is planned to commence and be completed in 2010.

    The permittee shall provide the Compliance Authority with updates to this schedule as necessary.

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

11. Actual Emissions Reporting: This permit is based on an analysis that compared baseline actual emissions with projected actual emissions and avoided the requirements of subsection 62-212.400(4) through (12), F.A.C. for several pollutants. Therefore, pursuant to Rule 62-212.300(1)(e), F.A.C., the permittee is subject to the following monitoring, reporting and recordkeeping provisions.

    a. The permittee shall monitor the emissions of any PSD pollutant that the Department identifies could increase as a result of the construction or modification and that is emitted by any emissions unit that could be affected; and, using the most reliable information available, calculate and maintain a record of the annual emissions, in tons per year on a calendar year basis, for a period of 5 years following resumption of regular operations after the change. Emissions shall be computed in accordance with the provisions in Rule 62-210.370, F.A.C., which are provided in Appendix C of this permit.

    b. The permittee shall report to the Department within 60 days after the end of each calendar year during the five-year period setting out the unit's annual emissions during the calendar year that preceded submission of the report. The report shall contain the following:

        1) The name, address and telephone number of the owner or operator of the major stationary source;

        2) The annual emissions as calculated pursuant to the provisions of 62-210.370, F.A.C., which are provided in Appendix C of this permit;

        3) If the emissions differ from the preconstruction projection, an explanation as to why there is a difference; and

4) Any other information that the owner or operator wishes to include in the report.

c. The information required to be documented and maintained pursuant to subparagraphs 62-212.300(1)(e)1 and 2, F.A.C., shall be submitted to the Department, which shall make it available for review to the general public.

For this project, the Department requires the annual reporting of actual SAM, SO_2, TRS and VOC emissions for the following units: No. 1 Power Boiler, No. 2 Power Boiler, No. 1 Bark Boiler, No. 2 Bark Boiler, No. 2 Recovery Boiler, No. 3 Recovery Boiler and the Pulping and MEE Systems.

[Application 1230001-023-AC; and Rules 62-212.300(1)(e) and 62-210.370, F.A.C.]

A. Nos. 3 and 4 Recovery Boilers

This subsection of the permit addresses the following emissions units.

ID	Emission Unit Description
006	**No. 2 Recovery Boiler**: Originally, this unit was manufactured by Babcock & Wilcox in 1957 as a direct contact evaporator unit. The project will convert this unit to a low-odor, non-direct contact evaporator unit. The maximum firing is 97,600 lb/hour of BLS to facilitate the recovery of the cooking liquor. Residual fuel oil is fired during startup, shutdown and occasionally to supplement BLS. Particulate matter emissions are controlled by a dry-bottom, rigid electrode ESP that was manufactured by Joy Western, originally installed in 1972 and upgraded in 2003. The following pollutants and parameters will be continuously monitored and recorded: CO, NO_X, TRS, oxygen and opacity. At permitted capacity, the exhaust gas flow rate is 122,849 dscfm at 8% oxygen with an exit temperature of 340° F. Exhaust gases exit a stack that is 10 feet in diameter and 225 feet tall.
007	**No. 3 Recovery Boiler**: Originally, this unit was manufactured by Combustion Engineering in 1964 as a direct contact evaporator unit. The project will convert this unit to a low-odor, non-direct contact evaporator. The maximum firing is 82,350 lb/hour of BLS to facilitate the recovery of the cooking liquor. Residual fuel oil is fired during startup, shutdown and occasionally to supplement BLS. Particulate matter emissions are controlled by a dry-bottom, rigid electrode ESP manufactured by Environmental Elements Corporation and originally installed in 1996. The following pollutants and parameters will be continuously monitored and recorded: CO, NO_X, TRS, oxygen and opacity. At permitted capacity, the exhaust gas flow rate is 119,300 dscfm at 8% oxygen with an exit temperature of 350° F. Exhaust gases exit a stack that is 9.5 feet in diameter and 225 feet tall.

{Permitting Note: In accordance with Rule 62-212.400(PSD), F.A.C., these emission units are subject to BACT determinations for CO, NO_X, PM and PM_{10} emissions, which are summarized in Appendix E of this permit.}

EXISTING APPLICABLE REGULATIONS

1. Existing Permits and Regulations: This permit supplements other previously issued air permits for the Nos. 2 and 3 Recovery Boilers, which include the following applicable state and federal regulations:

   a. The applicable provisions for recovery boilers at Kraft pulp mills as specified in Rule 62-296.404, F.A.C.; and

   b. The applicable provisions for recovery boilers at Kraft pulp mills as specified in NESHAP Subpart MM and the General Provisions in Subpart A of 40 CFR 63.

   [Rule 62-296.404, F.A.C.; and NESHAP Subparts A and MM in 40 CFR 63]

MODIFICATIONS

2. Authorized Modifications: The permittee is authorized to physically modify the recovery boilers to convert from direct contact evaporator (DCE) units to low-odor, non-direct contact evaporator (NDCE) units. The work includes the following types of new equipment and changes.

   a. *No. 2 Recovery Boiler*: Remove the existing cyclone evaporator and modify the ductwork; change the drum internals and feed/riser tubes as necessary; replace or modify flue ducts from the generating section outlet to the cyclone evaporator outlet; install a new economizer with new soot blowers; increase the superheater surface areas; install an ash collection system for the new economizer and ducts; install a new mix tank to mix ash with black liquor; and install a tertiary air fan as part of the over-fire air system to increase total combustion air by approximately 20%. The permittee shall install, operate and maintain equipment to continuously monitor and record the flow rates of each authorized fuel (e.g. flow meters with integrators). Construction is planned to commence and be completed in 2009.

   b. *No. 3 Recovery Boiler*: Remove the existing cascade evaporator and modify the ductwork; change the drum internals and feed/riser tubes as necessary; install an additional economizer; install two new superheater platens to increase surface area; install a new water coil air heater to preheat and increase the primary air temperature in lower furnace; install new flue gas duct to connect outlet of existing economizer to inlet of new economizer; install new flue gas duct to connect outlet of new economizer to inlet of electrostatic precipitator; and install an ash collection system for the new economizer and ducts. The permittee shall install, operate and maintain equipment to continuously monitor and record the flow rates of each authorized fuel (e.g. flow meters with integrators). Construction is planned to commence and be completed in 2010.

c. *Common System Changes*: See subsection B of this permit for additional work.

[Application No. 1230001-023-AC; and Rule 62-212.300, F.A.C.]

AUTHORIZED FUELS, CAPACITIES AND RESTRICTIONS

3. Authorized Fuels: The Nos. 2 and 3 Recovery Boilers are authorized to fire BLS as the primary fuel. The following fuels may be fired to supplement BLS and as otherwise specified:

   a. No. 6 residual oil with a maximum sulfur content of 2.5% by weight during startup and shutdown;

   b. No. 2 distillate oil with a maximum sulfur content of 0.5% by weight as a pilot fuel during startup, shutdown and for drying equipment after a water wash;

   c. Subject to the provisions in Appendix G of this permit, incidental amounts of on-specification used oil generated on site may be blended and fired with other authorized oil; and

   d. Natural gas as a pilot fuel during startup, shutdown and for drying equipment after a water wash.

   [Application No. 1230001-023-AC; and Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

4. Capacity – No. 2 Recovery Boiler

   a. The maximum operating capacity is 97,600 lb/hour of BLS (1-hour average), which is equivalent to a heat input rate of 625 MMBtu per hour based on a fuel heating value of 6400 Btu/lb of BLS. This is also equivalent to approximately 32.53 tons per hour of air-dried unbleached pulp produced based on 1.5 tons of BLS/ton air-dried unbleached pulp. At the maximum firing rate, the boiler will produce approximately 380,000 lb/hour of steam.

   b. The total maximum oil firing rate is 2192 gallons of oil per hour, which is equivalent to a heat input rate of 320 MMBtu per hour based on a fuel heating value of 146 MMBtu per 1000 gallons of oil. The oil firing system consists of eight oil burners. Each oil burner has a capacity of 40 MMBtu per hour.

   [Application No. 1230001-023-AC; and Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

5. Capacity – No. 3 Recovery Boiler

   a. The maximum operating capacity is 82,350 lb/hour of BLS (1-hour average), which is equivalent to a heat input rate of 527 MMBtu per hour based on a fuel heating value of 6400 Btu/lb of BLS. This is also equivalent to approximately 27.45 tons per hours of air-dried unbleached pulp produced assuming 1.5 tons BLS/ton air-dried unbleached pulp. At the maximum firing rate, the boiler will produce approximately 325,000 lb/hour of steam.

   b. The total maximum oil firing rate is 603 gallons of oil per hour, which is equivalent to a heat input rate of 80 MMBtu per hour based on a fuel heating value of 146 MMBtu per 1000 gallons of oil. The oil firing system consists of four oil burners. Each oil burner has a capacity of 20 MMBtu per hour.

   [Application No. 1230001-023-AC; and Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

6. Restricted Operation: Although the hours of operation are not restricted, the Nos. 2 and 3 Recovery Boilers are subject to the following limitations.
   a. No more than 1,700,000 gallons of oil shall be fired in the No. 2 Recovery Boiler during any consecutive 12-month period, rolling total.
   b. No more than 2,000,000 gallons of oil shall be fired in the No. 3 Recovery Boiler during any consecutive 12-month period, rolling total.
   c. The above oil firing limitations include all amounts of residual oil, distillate oil and on-specification used oil as authorized by this permit.

   [Application No. 1230001-023-AC; and Rules 62-210.200(PTE) and 62-212.400(PSD), F.A.C.]

AIR POLLUTION CONTROL EQUIPMENT

7. ESP: The permittee shall operate and maintain an ESP to control particulate matter emissions and minimize opacity from each recovery boiler to achieve the emissions standards specified by this permit.
   a. *No. 2 Recovery Boiler*: The ESP was manufactured by Joy Western and originally installed in 1972. It was upgraded by Environmental Elements Corporation in 2003 with the following specifications: dry-bottom; rigid electrodes; two chambers; four fields per chamber; a design inlet flow rate of 230,000 acfm at 500° F; an inlet dust loading of 2-3 grains per acf; and a collection area of 380.9 feet^2/1000 acfm.
   b. *No. 3 Recovery Boiler*: The ESP was manufactured by Environmental Elements Corporation and originally installed in 1996 with the following specifications: dry-bottom; rigid electrodes; two chambers; three fields per chamber; a design inlet flow rate of 235,000 acfm at 375° F; an inlet dust loading of 3 grains per acf; and a specific collection area 273.4 feet^2/1000 acfm.

   Except for infrequent periods of maintenance, all fields of each ESP shall be functioning when the boiler is in operation. Based on satisfactory tests demonstrating compliance with the PM and opacity standards of this permit, each ESP may operate with a single field removed from service to facilitate maintenance on that field. Such periods of maintenance that do not create excess opacity shall be corrected as soon as practicable. [Application No. 1230001-023-AC; and Rules 62-4.070(3) and 62-212.400(PSD), F.A.C.]

EMISSIONS AND PERFORMANCE STANDARDS

8. CO Standards
   a. *No. 2 Recovery Boiler*: As determined by data collected from the required CEMS, CO emissions shall not exceed 400.0 ppmvd corrected to 8% oxygen and 214.1 lb/hour based on a 30-day rolling average excluding periods of startup and shutdown.
   b. *No. 3 Recovery Boiler*: As determined by data collected from the required CEMS, CO emissions shall not exceed 400.0 ppmvd corrected to 8% oxygen and 208.0 lb/hour based on a 30-day rolling average excluding periods of startup and shutdown.

   The new standards become effective after completing shakedown of each boiler, but no later than 180 calendar days following first fire after completing the conversion. If a 30-day CEMS average shows an exceedance of the CO standards, the permittee may exclude the following amounts of CEMS data to determine compliance: no more than eight hours per startup resulting in high CO emissions; and no more than eight hours per shutdown resulting in high CO emissions. Data collected during periods of malfunctions must be included within each compliance average. [Rules 62-212.400(BACT) and 62-210.700(5), F.A.C.]

9. NOx Standards

a. *No. 2 Recovery Boiler*: As determined by data collected from the required CEMS, NO_X emissions shall not exceed 80.0 ppmvd corrected to 8% oxygen and 70.4 lb/hour based on a 30-day rolling average excluding periods of startup and shutdown.

b. *No. 3 Recovery Boiler*: As determined by data collected from the required CEMS, NO_X emissions shall not exceed 80.0 ppmvd corrected to 8% oxygen and 68.3 lb/hour based on a 30-day rolling average excluding periods of startup and shutdown.

The new standards become effective after completing shakedown of each boiler, but no later than 180 calendar days following first fire after completing the conversion. If a 30-day CEMS average shows an exceedance of the NO_X standards, the permittee may exclude the following amounts of CEMS data to determine compliance: no more than eight hours per startup resulting in high NO_X emissions; and no more than eight hours per shutdown resulting in high NO_X emissions. Data collected during periods of malfunctions must be included within each compliance average. [Rules 62-212.400(BACT) and 62-210.700(5), F.A.C.]

10. Opacity Standard: As determined by the existing COMS and/or EPA Method 9, the opacity from each recovery boiler shall not exceed 20% opacity based on 6-minute averages except for the following periods of startup, shutdown and malfunction.

    a. *Startup*: When the Nos. 2 or 3 Recovery Boilers are being started up from outages, visible emissions shall not exceed 35% opacity based on 6-minute averages as determined by the existing COMS and/or EPA Method 9. Opacity in excess of 35% during startups 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 four hours per startup.

    b. *Shutdown*: When the Nos. 2 or 3 Recovery Boilers are being shut down for outages, visible emissions shall not exceed 35% opacity based on 6-minute averages as determined by the existing COMS and/or EPA Method 9. Opacity in excess of 35% during shutdowns 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 four hours per shutdown.

    c. *ESP Malfunction*: during periods of maintenance to address precipitator malfunctions, visible emissions shall not exceed 35% opacity based on 6-minute averages as determined by the existing COMS and/or EPA Method 9. Excess opacity during malfunction repairs 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 four hours in any 24-hour period. This provision applies when it is necessary to shut down a chamber to effect the ESP repair.

The new standards become effective after completing shakedown of each recovery boiler, but no later than 60 calendar days following first fire after completing the conversion.

[Rules 62-212.400(BACT) and 62-210.700(1), F.A.C.]

11. PM Standards

    a. *No. 2 Recovery Boiler*: As determined by EPA Method 5, PM emissions shall not exceed 0.030 grains per dscf corrected to 8% oxygen and 31.6 lb/hour based on the average of three stack test runs.

    b. *No. 3 Recovery Boiler*: As determined by EPA Method 5, PM emissions shall not exceed 0.030 grains per dscf corrected to 8% oxygen and 30.7 lb/hour based on the average of three stack test runs.

    [Rule 62-212.400(BACT), F.A.C.]

CONTINUOUS MONITORING PROVISIONS

{Permitting Note: The Nos. 2 and 3 Recovery Boilers have existing continuous monitors for determining opacity, oxygen and TRS emissions. The following requirements are in addition to the existing equipment.}

12. New CO and NOx CEMS: The permittee shall install, calibrate, operate and maintain CEMS to measure and record emissions in terms of the applicable standards to demonstrate compliance with the CO and NO_X standards for the Nos. 2 and 3 Recovery Boilers. The permittee shall comply with the conditions of Appendix F (Standard Continuous Emissions Monitoring Requirements) of this permit for each CEMS required to be installed by this permit as the compliance method for a SIP-based emission standard. Within 180 calendar days of completing the conversion of each recovery boiler, the permittee shall have installed and certified each required CEMS in accordance with the applicable performance specifications. [Rules 62-4.070(3) and 62-212.400(PSD), F.A.C.]

13. Existing COMS: To demonstrate compliance with the opacity standard for the Nos. 2 and 3 Recovery Boilers, the permittee shall calibrate, operate and maintain the existing COMS to measure and record opacity in terms of the applicable standard. Each COMS shall be certified, calibrated and maintained to meet Performance Specification 1 in Appendix B of 40 CFR 60. The permittee shall report emissions in excess of a standard within one day of discovery. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

14. Alternative Flue Gas Flow Monitoring: As an alternative to a continuous flue gas flow monitor, the permittee may develop a site specific F-factor for BLS in accordance with the following procedure.

    a. Submit a test protocol for approval to the Bureau of Air Regulation for developing a site specific F-factor for BLS.

    b. Upon written approval from the Bureau of Air Regulation, conduct the testing program in accordance with the protocol.

    c. Develop a site-specific F-factor for BLS based on the testing program and operational data.

    d. Submit a report on the testing program to the Bureau of Air Regulation summarizing: the tests conducted explanations of any deviations from the test protocol, the data collected, the proposed site-specific F-factor for BLS, and an evaluation of the estimated flow rates compared to the actual measured flow rates.

    e. Submit a request for approval to the Bureau of Air Regulation to use the proposed site-specific F-factor for BLS.

    f. Upon written approval by the Bureau of Air Regulation, the permittee may begin using the site-specific F-factor for BLS to determine the exhaust flow rate. If the Bureau of Air Regulation does not approve the site-specific F-factor for BLS, the permittee shall install a continuous flow monitor.

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

COMPLIANCE TESTING REQUIREMENTS

15. Standard Testing Requirements: All required emissions tests shall be conducted in accordance with the requirements specified in Appendix D (Standard Testing Requirements) of this permit. [Rules 62-204.800, 62-297.100 and 62-297.310, F.A.C.; and 40 CFR 60, Appendix A]

16. Test Notification: The permittee shall notify the Compliance Authority in writing at least 15 days prior to any required tests. [Rule 62-297.310(7)(a)9, F.A.C.]

17. Test Methods: When required, tests shall be performed in accordance with the following methods.

EPA Method	Description of Method and Comments

EPA Method	Description of Method and Comments
1 - 4	Methods for Determining Traverse Points, Velocity, Flow Rate, Gas Analysis, and Moisture Content These methods shall be performed as necessary to support other methods.
5	Method for Determining Particulate Matter Emissions
7E	Method for Determining NO_X Emissions (Instrumental)
9	Method for Determining Opacity Observations
10	Method for Determining Carbon Monoxide Emissions (Instrumental) The method shall be based on a continuous sampling train.

The above methods are specified in Appendix A of 40 CFR 60 and are adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used unless prior written approval is received from the Department. [Rules 62-4.070(3), 62-204.800 and 62-212.400(BACT), F.A.C.; and 40 CFR 60, Appendix A]

18. Compliance Tests: In accordance with the following requirements, the permittee shall have stack tests conducted to demonstrate compliance with the PM emissions standards.

    a. *Initial Tests*: Initial compliance tests shall be conducted within 60 calendar days after completing shakedown and achieving permitted capacity for each boiler, but no later than 180 calendar days following first fire after completing the conversion.

    b. *Annual Tests*: During each federal fiscal year (October 1st to September 30th), compliance tests shall be conducted to determine PM emissions.

    c. *Special Tests*: Special compliance tests shall be conducted when the Department requests a special test pursuant to Rule 62-297.310(7)(b), F.A.C.

    d. *Test Fuel and Conditions*: Separate tests shall be conducted while operating with all fields in service and with one field removed from service. Compliance tests shall be conducted when firing BLS at permitted capacity.

    e. *Operational Data for Tests*: For each test run, the permittee shall monitor and record the fuel feed rate (lb of BLS/hour), the secondary power input (kW) to the ESP, and the number of active fields for the ESP.

    [Rules 62-4.070(3), 62-297.310 and 62-212.400(BACT), F.A.C.]

RECORDS AND REPORTS

19. Stack Test Reports: For all required stack tests, the permittee shall prepare and submit reports to the Compliance Authority in accordance with the requirements specified in Appendix D (Common Testing Requirements) of this permit. For each test run, the report shall also report: the fuel feed rate (lb of BLS/hour); the power input (kW) to the ESP; the number of active fields for the ESP; the flue gas oxygen content; CO, NO_X and TRS CEMS data; and opacity COMS data. [Rule 62-297.310(8), F.A.C.]

20. Semiannual Monitoring Reports: The permittee shall submit a written report to the Compliance Authority for the following semiannual reporting periods: January 1st – June 30th; and July 1st – December 31st. For each reporting period, the permittee shall summarize the following: quantity of each authorized fuel fired; total oil fired; sulfur content of each oil fired; CO and NO_X emissions; stack opacity; and CEMS and COMS monitor availability. The reports shall identify any exceedance of an emissions standard or performance limitation. Each report is due within 30 days following the reporting period. [Rules 62-4.070(3), 62-210.370 and 62-212.400(PSD), F.A.C.]

21. CEMS for Reporting Annual Emissions: The permittee shall use data from each required CEMS when calculating annual emissions for purposes of computing actual emissions, baseline actual emissions and net emissions increase, as defined at Rule 62-210.200, F.A.C., and for purposes of computing emissions pursuant to the reporting requirements of Rules 62-210.370(3) and 62-212.300(1)(e), F.A.C. The permittee shall follow the procedures in Appendix C (Common Conditions) and Appendix E (Standard Continuous Monitoring Requirements) of this permit for calculating annual emissions.

B. Other Miscellaneous Changes

This subsection of the permit addresses the following emissions units and activities.

ID	Emission Unit Description
002	No. 1 Power Boiler
003	No. 2 Power Boiler
004	No. 1 Bark Boiler
019	No. 2 Bark Boiler
046	Pulping and Multiple Effect Evaporator (MEE) Systems
N/A	Black Liquor Oxidation (BLOX) System
N/A	28 MW Condensing Steam Turbine-Electrical Generator

{Permitting Note: In accordance with Rule 62-212.400(2), F.A.C., the permittee conducted a PSD netting analysis that compared baseline actual emissions with projected actual emissions. Based on the analysis, the project is subject to PSD preconstruction review for CO, NO_X, PM, and PM_{10} emissions. However, the above emissions units were not being modified or will not emit these PSD-significant pollutants.}

EXISTING APPLICABLE REGULATIONS

1. Existing Permits and Regulations: This permit supplements other previously issued air permits for these emissions units, which include the following applicable state and federal regulations:

   a. The applicable provisions for regulated equipment at Kraft pulp mills as specified in Rule 62-296.404, F.A.C.;

   b. The applicable provisions for fossil fuel fired steam generators with a maximum heat input rate less than 250 MMBtu per hour as specified in Rule 62-296.406, F.A.C.;

   c. The applicable provisions for carbonaceous fuel burning equipment as specified in Rule 62-296.410, F.A.C.; and

   d. The applicable NESHAP provisions for regulated equipment at Kraft pulp mills specified in Subpart S and the corresponding General Provisions in Subpart A of 40 CFR 63.

   [Rules 62-296.404, 62-296.406, and 62-296.410, F.A.C.; and NESHAP Subparts A and S in 40 CFR 63]

NEW EQUIPMENT AND MODIFICATIONS

2. Pulping and MEE Systems (EU-046) - Modified: The permittee is authorized to install and operate two new forced-circulation/crystallizer black liquor concentrators (Nos. 2 and 3). One new concentrator will be installed in conjunction with each recovery boiler conversion. Each unit will consist of: two tube and shell heat exchangers; two recirculation pumps; a crystallizer flash tank; a product flash tank; and a product transfer pump. Each new concentrator will be tied into an existing 5-effect black liquor MEE and will function as the first effect. The maximum capacity of each new concentrator is dependent on the existing MEE (122,356 lb/hour and 127,350 lb/hour for the Nos. 2 and 3 MEE, respectively). The new concentrators will flash-off moisture from the black liquor to increase the solids content from approximately 50% to 72%. A new black liquor storage tank with a capacity of approximately 132,000 gallons will be added to store the 72% solids black liquor. Changes will increase the non-condensable gases (NCG) generated from the MEE system, which will be collected controlled by combustion in the No. 1 Bark Boiler (primary control) or the No. 1 Power Boiler (secondary control), which also controls TRS emissions with a white liquor pre-

scrubber.. The modified MEE system remains subject to all existing applicable requirements. [Application No. 1230001-023-AC; Rules 62-204.800, 62-212.300, F.A.C., and 40 CFR 63, Subparts A and S]

3. Common System Changes: The permittee is authorized to install and modify miscellaneous equipment needed for both recovery boilers and concentrators such as: install piping from new concentrators to new and existing storage tanks; install piping from the concentrated liquor storage tanks to the recovery boiler salt cake mix tanks; install recirculation pump/piping on concentrated liquor storage tanks to minimize tank cone plugging; install transfer line between new and existing concentrated liquor storage tanks; install new recirculation pumps on existing East 50% black liquor storage tank for ash mixing; and install new recirculation pumps on ash mix tanks. [Application No. 1230001-023-AC and Rule 62-212.300, F.A.C.]

4. Condensing Steam Turbine-Electrical Generator Set - New: The permittee is authorized to install and operate a new condensing turbine-electrical generator set with a rated capacity of 28 MW. [Application No. 1230001-023-AC and Rule 62-212.300, F.A.C.]

5. Fuel Flow Meters: The permittee shall install, operate and maintain equipment to continuously monitor and record the flow rates of each authorized liquid and gaseous fuel (e.g. flow meters with integrators) for the following units: No. 1 Power Boiler, No. 2 Power Boiler, No. 1 Bark Boiler and No. 2 Bark Boiler. The equipment shall be installed and properly functioning prior to startup of the new 28 MW condensing turbine-electrical generator set. Existing equipment may satisfy this requirement. The firing rates of bark/wood shall be determined from actual monitored steam production rates, known boiler efficiencies, the bark/wood heating value, and the contributions from other fuels fired. [Rules 62-4.070(3) and 62-210.370, F.A.C.]

PERFORMANCE RESTRICTIONS

6. BLOX System - Shutdown: Currently, the BLOX System oxidizes black liquor prior to use in the Nos. 2 and 3 Recovery Boiler. After the recovery boilers are converted from DCE to low-odor, NDCE units, the BLOX System will no longer be necessary. After completing conversion of the No. 2 Recovery Boiler, the operating rate of the BLOX System will be reduced to support only the No. 3 Recovery Boiler. After completing conversion of the No. 3 Recovery Boiler, the permittee shall permanently shutdown the BLOX System. The permittee shall provide written notice of the permanent shutdown of the BLOX System. [Rule 62-4.070(3), F.A.C.]

7. Oil Firing Restrictions: The existing power boilers are subject to the following new oil firing restrictions.

   a. *No. 1 Power Boiler*: After completing installation of the new 28 MW condensing steam turbine-electrical generator, the No. 1 Power Boiler shall fire no more than 5,623,000 gallons of oil during any consecutive 12-month rolling average.

   b. *No. 2 Power Boiler*: After completing installation of the new 28 MW condensing steam turbine-electrical generator, the No. 2 Power Boiler shall fire only natural gas.

   The above oil firing limitations include all amounts of authorized oil (e.g., residual oil, distillate oil and facility-generated on-specification used oil). The permittee shall install, operate and maintain fuel flow meters to monitor the fuel consumption in each boiler. This permit does not otherwise alter the current authorized fuels and firing rates of any of these boilers. [Application 1230001-023-AC; and Rules 62-4.070(3) and 62-212.400(PSD), F.A.C.]

   The permittee shall keep records on a monthly basis to ensure compliance with the oil firing restrictions.

RECORDS AND REPORTS

B. Other Miscellaneous Changes

8. Monthly Fuel Records: After completing construction of the new 28 MW condensing turbine-electrical generator set, the permittee shall begin calculating and recording the fuel firing rates of the following boilers: No. 1 Power Boiler, No. 2 Power Boiler, No. 1 Bark Boiler and No. 2 Bark Boiler. Within seven days following each month, the permittee shall record the gallons of oil fired for each month and each consecutive 12-month period. The fuel firing rates shall also be used to determine SAM and SO_2 emissions for these units. [Application 1230001-023-AC; and Rules 62-4.070(3) and 62-212.400(PSD), F.A.C.]

9. Fuel Sulfur Content: The permittee shall monitor the fuel sulfur content according to the following conditions.

   a. For each delivery of No. 6 residual oil, the permittee shall retain records of the quantity of oil delivered and the certified vendor analysis identifying the sulfur content of the oil delivered. For each day deliveries are made, the permittee shall recalculate the fuel oil sulfur content of the common tank based on the previous tank conditions and the amounts and sulfur contents of the deliveries made during the day. For incidental amounts of facility-generated on-specification used oil added to the residual oil tank, the amount of used oil added shall be tracked and the sulfur content shall be assumed equivalent to that of the oil in the common tank prior to adding the used oil. At least once during each calendar month, the permittee shall take a sample from the common tank and have it analyzed for the sulfur content and heating value. The analytical results shall be maintained on site and a summary provided with the Annual Operating Report.

   b. For each delivery of distillate oil, the permittee shall retain records of the quantity of oil delivered and the certified vendor analysis identifying the sulfur content of the oil delivered. The actual fuel sulfur content may be calculated or a sample shall be taken and analyzed for the sulfur content. This shall be the fuel sulfur content used for emissions calculations until a subsequent delivery.

   c. The following approved analytical methods shall be used for oil: ASTM Method D-129, ASTM D-1552, ASTM D-2622, and ASTM D-4294. Other more recent or equivalent ASTM methods or Department-approved methods are also acceptable.

   d. The provisions for facility-generated on-specification used oil are specified in Appendix G of this permit.

   e. The permittee shall use vendor information to determine the sulfur content of natural gas.

   The actual fuel sulfur content shall be used to determine SAM and SO_2 emissions for the No. 1 Power Boiler, No. 2 Power Boiler, No. 1 Bark Boiler and No. 2 Bark Boiler. [Application 1230001-023-AC; and Rules 62-4.070(3) and 62-212.400(PSD), F.A.C.]

CONTENTS

CITATION FORMATS AND GLOSSARY OF COMMON TERMS

CITATION FORMATS

The following illustrate the formats used in the permit to identify applicable requirements from permits and regulations.

Old Permit Numbers

Example: Permit No. AC50-123456 or Permit No. AO50-123456

Where: "AC" identifies the permit as an Air Construction Permit

"AO" identifies the permit as an Air Operation Permit

"123456" identifies the specific permit project number

New Permit Numbers

Example: Permit Nos. 099-2222-001-AC, 099-2222-001-AF, 099-2222-001-AO, or 099-2222-001-AV

Where: "099" represents the specific county ID number in which the project is located

"2222" represents the specific facility ID number for that county

"001"identifies the specific permit project number

"AC" identifies the permit as an air construction permit

"AF" identifies the permit as a minor source federally enforceable state operation permit

"AO" identifies the permit as a minor source air operation permit

"AV" identifies the permit as a major Title V air operation permit

PSD Permit Numbers

Example: Permit No. PSD-FL-317

Where: "PSD" means issued pursuant to the preconstruction review requirements of the Prevention of Significant Deterioration of Air Quality

"FL" means that the permit was issued by the State of Florida

"317" identifies the specific permit project number

Florida Administrative Code (F.A.C.)

Example: [Rule 62-213.205, F.A.C.]

Means: Title 62, Chapter 213, Rule 205 of the Florida Administrative Code

Code of Federal Regulations (CFR)

Example: [40 CRF 60.7]

Means: Title 40, Part 60, Section 7

GLOSSARY OF COMMON TERMS

° F: degrees Fahrenheit

acfm: actual cubic feet per minute

ARMS: Air Resource Management System (Department's database)

BACT: best available control technology

Btu: British thermal units

CAM: compliance assurance monitoring

CEMS: continuous emissions monitoring system

cfm: cubic feet per minute

CFR: Code of Federal Regulations

CO: carbon monoxide

COMS: continuous opacity monitoring system

CITATION FORMATS AND GLOSSARY OF COMMON TERMS

DEP: Department of Environmental Protection

Department: Department of Environmental Protection

dscfm: dry standard cubic feet per minute

EPA: Environmental Protection Agency

ESP: electrostatic precipitator (control system for reducing particulate matter)

EU: emissions unit

F.A.C.: Florida Administrative Code

F.D.: forced draft

F.S.: Florida Statutes

FGR: flue gas recirculation

Fl: fluoride

ft^2: square feet

ft^3: cubic feet

gpm: gallons per minute

gr: grains

HAP: hazardous air pollutant

Hg: mercury

I.D.: induced draft

ID: identification

kPa: kilopascals

lb: pound

MACT: maximum achievable technology

MMBtu: million British thermal units

MSDS: material safety data sheets

MW: megawatt

NESHAP: National Emissions Standards for Hazardous Air Pollutants

NO_X: nitrogen oxides

NSPS: New Source Performance Standards

O&M: operation and maintenance

O_2: oxygen

Pb: lead

PM: particulate matter

PM_{10}: particulate matter with a mean aerodynamic diameter of 10 microns or less

PSD: prevention of significant deterioration

psi: pounds per square inch

PTE: potential to emit

RACT: reasonably available control technology

RATA: relative accuracy test audit

SAM: sulfuric acid mist

scf: standard cubic feet

scfm: standard cubic feet per minute

SIC: standard industrial classification code

SNCR: selective non-catalytic reduction (control system used for reducing emissions of nitrogen oxides)

SO_2: sulfur dioxide

TPH: tons per hour

TPY: tons per year

UTM: Universal Transverse Mercator coordinate system

VE: visible emissions

VOC: volatile organic compounds

GENERAL CONDITIONS

The permittee shall comply with the following general conditions from Rule 62-4.160, F.A.C.

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, F.S. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these 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), F.S., 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 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 permittee to cause pollution in contravention of F.S. 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 or 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 and records 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.
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 noncompliance, 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 F.S. or Department rules, except where such use is prescribed by Sections 403.73 and 403.111, F.S. 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 F.S. after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by F.S. or Department rules.
11. This permit is transferable only upon Department approval in accordance with 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:
    a. Determination of Best Available Control Technology (applicable);
    b. Determination of Prevention of Significant Deterioration (applicable); and
    c. Compliance with New Source Performance Standards (not newly applicable).
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 or 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:
        1) The date, exact place, and time of sampling or measurements;
        2) The person responsible for performing the sampling or measurements;
        3) The dates analyses were performed;
        4) The person responsible for performing the analyses;
        5) The analytical techniques or methods used; and
        6) 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.

Unless otherwise specified in the permit, the following conditions apply.

EMISSIONS AND CONTROLS

1. 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 permittee shall notify each Compliance Authority as soon as possible, but at least within one working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; 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 or the regulations. [Rule 62-4.130, F.A.C.]

2. Circumvention: The permittee shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Rule 62-210.650, F.A.C.]

3. Excess Emissions Allowed: Excess emissions resulting from startup, shutdown or malfunction of any emissions unit 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 2 hours in any 24-hour period unless specifically authorized by the Department for longer duration. Pursuant to Rule 62-210.700(5), F.A.C., the permit subsection may specify more or less stringent requirements for periods of excess emissions. Rule 62-210-700(Excess Emissions), F.A.C., cannot vary or supersede any federal NSPS or NESHAP provision. [Rule 62-210.700(1), F.A.C.]

4. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. [Rule 62-210.700(4), F.A.C.]

5. Excess Emissions - Notification: In case of excess emissions resulting from malfunctions, the permittee shall notify the Compliance Authority 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. [Rule 62-210.700(6), F.A.C.]

6. VOC or OS Emissions: No person shall store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds (VOC) or organic solvents (OS) without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department. [Rule 62-296.320(1), F.A.C.]

7. Objectionable Odor Prohibited: No person shall cause, suffer, allow or permit the discharge of air pollutants, which cause or contribute to an objectionable odor. An "objectionable odor" means any odor present in the outdoor atmosphere which by itself or in combination with other odors, is or may be harmful or injurious to human health or welfare, which unreasonably interferes with the comfortable use and enjoyment of life or property, or which creates a nuisance. [Rules 62-296.320(2) and 62-210.200(Definitions), F.A.C.]

8. General Visible Emissions: No person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity equal to or greater than 20% opacity. This regulation does not impose a specific testing requirement. [Rule 62-296.320(4)(b)1, F.A.C.]

9. Unconfined Particulate Emissions: During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as covering and/or application of water or chemicals to the affected areas, as necessary. [Rule 62-296.320(4)(c), F.A.C.]

RECORDS AND REPORTS

10. Records Retention: All measurements, records, and other data required by this permit shall be documented in a permanent, legible format and retained for at least 5 years following the date on which such measurements, records, or data are recorded. Records shall be made available to the Department upon request. [Rule 62-213.440(1)(b)2, F.A.C.]

11. Emissions Computation and Reporting

    a. *Applicability.* This rule sets forth required methodologies to be used by the owner or operator of a facility for computing actual emissions, baseline actual emissions, and net emissions increase, as defined at Rule 62-210.200, F.A.C., and for computing emissions for purposes of the reporting requirements of subsection 62-210.370(3) and paragraph 62-212.300(1)(e), F.A.C., or of any permit condition that requires emissions be computed in accordance with this rule. This rule is not intended to establish methodologies for determining compliance with the emission limitations of any air permit.

b. *Computation of Emissions.* For any of the purposes set forth in subsection 62-210.370(1), F.A.C., the owner or operator of a facility shall compute emissions in accordance with the requirements set forth in this subsection.

(1) Basic Approach. The owner or operator shall employ, on a pollutant-specific basis, the most accurate of the approaches set forth below to compute the emissions of a pollutant from an emissions unit; provided, however, that nothing in this rule shall be construed to require installation and operation of any continuous emissions monitoring system (CEMS), continuous parameter monitoring system (CPMS), or predictive emissions monitoring system (PEMS) not otherwise required by rule or permit, nor shall anything in this rule be construed to require performance of any stack testing not otherwise required by rule or permit.

(a) If the emissions unit is equipped with a CEMS meeting the requirements of paragraph 62-210.370(2)(b), F.A.C., the owner or operator shall use such CEMS to compute the emissions of the pollutant, unless the owner or operator demonstrates to the department that an alternative approach is more accurate because the CEMS represents still-emerging technology.

(b) If a CEMS is not available or does not meet the requirements of paragraph 62-210.370(2)(b), F.A.C, but emissions of the pollutant can be computed pursuant to the mass balance methodology of paragraph 62-210.370(2)(c), F.A.C., the owner or operator shall use such methodology, unless the owner or operator demonstrates to the department that an alternative approach is more accurate.

(c) If a CEMS is not available or does not meet the requirements of paragraph 62-210.370(2)(b), F.A.C., and emissions cannot be computed pursuant to the mass balance methodology, the owner or operator shall use an emission factor meeting the requirements of paragraph 62-210.370(2)(d), F.A.C., unless the owner or operator demonstrates to the department that an alternative approach is more accurate.

(2) Continuous Emissions Monitoring System (CEMS).

(a) An owner or operator may use a CEMS to compute emissions of a pollutant for purposes of this rule provided:

1) The CEMS complies with the applicable certification and quality assurance requirements of 40 CFR Part 60, Appendices B and F, or, for an acid rain unit, the certification and quality assurance requirements of 40 CFR Part 75, all adopted by reference at Rule 62-204.800, F.A.C.; or

2) The owner or operator demonstrates that the CEMS otherwise represents the most accurate means of computing emissions for purposes of this rule.

(b) Stack gas volumetric flow rates used with the CEMS to compute emissions shall be obtained by the most accurate of the following methods as demonstrated by the owner or operator:

1) A calibrated flowmeter that records data on a continuous basis, if available; or

2) The average flow rate of all valid stack tests conducted during a five-year period encompassing the period over which the emissions are being computed, provided all stack tests used shall represent the same operational and physical configuration of the unit.

(c) The owner or operator may use CEMS data in combination with an appropriate f-factor, heat input data, and any other necessary parameters to compute emissions if such method is demonstrated by the owner or operator to be more accurate than using a stack gas volumetric flow rate as set forth at subparagraph 62-210.370(2)(b)2., F.A.C., above.

(3) Mass Balance Calculations.

(a) An owner or operator may use mass balance calculations to compute emissions of a pollutant for purposes of this rule provided the owner or operator:

1) Demonstrates a means of validating the content of the pollutant that is contained in or created by all materials or fuels used in or at the emissions unit; and

2) Assumes that the emissions unit emits all of the pollutant that is contained in or created by any material or fuel used in or at the emissions unit if it cannot otherwise be accounted for in the process or in the capture and destruction of the pollutant by the unit's air pollution control equipment.

(b) Where the vendor of a raw material or fuel which is used in or at the emissions unit publishes a range of pollutant content from such material or fuel, the owner or operator shall use the highest value of the range to compute the emissions, unless the owner or operator demonstrates using site-specific data that another content within the range is more accurate.

(c) In the case of an emissions unit using coatings or solvents, the owner or operator shall document, through purchase receipts, records and sales receipts, the beginning and ending VOC inventories, the amount of VOC purchased during the computational period, and the amount of VOC disposed of in the liquid phase during such period.

(4) Emission Factors.

a. An owner or operator may use an emission factor to compute emissions of a pollutant for purposes of this rule provided the emission factor is based on site-specific data such as stack test data, where available, unless the owner or operator demonstrates to the department that an alternative emission factor is more accurate. An owner or operator using site-specific data to derive an emission factor, or set of factors, shall meet the following requirements.

1) If stack test data are used, the emission factor shall be based on the average emissions per unit of input, output, or gas volume, whichever is appropriate, of all valid stack tests conducted during at least a five-year period encompassing the period over which the emissions are being computed, provided all stack tests used shall represent the same operational and physical configuration of the unit.

2) Multiple emission factors shall be used as necessary to account for variations in emission rate associated with variations in the emissions unit's operating rate or operating conditions during the period over which emissions are computed.

3) The owner or operator shall compute emissions by multiplying the appropriate emission factor by the appropriate input, output or gas volume value for the period over which the emissions are computed. The owner or operator shall not compute emissions by converting an emission factor to pounds per hour and then multiplying by hours of operation, unless the owner or operator demonstrates that such computation is the most accurate method available.

b. If site-specific data are not available to derive an emission factor, the owner or operator may use a published emission factor directly applicable to the process for which emissions are computed. If no directly-applicable emission factor is available, the owner or operator may use a factor based on a similar, but different, process.

(5) Accounting for Emissions During Periods of Missing Data from CEMS, PEMS, or CPMS. In computing the emissions of a pollutant, the owner or operator shall account for the emissions during periods of missing data from CEMS, PEMS, or CPMS using other site-specific data to generate a reasonable estimate of such emissions.

(6) Accounting for Emissions During Periods of Startup and Shutdown. In computing the emissions of a pollutant, the owner or operator shall account for the emissions during periods of startup and shutdown of the emissions unit.

(7) Fugitive Emissions. In computing the emissions of a pollutant from a facility or emissions unit, the owner or operator shall account for the fugitive emissions of the pollutant, to the extent quantifiable, associated with such facility or emissions unit.

(8) Recordkeeping. The owner or operator shall retain a copy of all records used to compute emissions pursuant to this rule for a period of five years from the date on which such emissions information is submitted to the department for any regulatory purpose.

c. *Annual Operating Report for Air Pollutant Emitting Facility*

(1) The Annual Operating Report for Air Pollutant Emitting Facility (DEP Form No. 62-210.900(5)) shall be completed each year for the following facilities:

(a) All Title V sources.

(b) All synthetic non-Title V sources.

(c) All facilities with the potential to emit ten (10) tons per year or more of volatile organic compounds or twenty-five (25) tons per year or more of nitrogen oxides and located in an ozone nonattainment area or ozone air quality maintenance area.

(d) All facilities for which an annual operating report is required by rule or permit.

(2) Notwithstanding paragraph 62-210.370(3)(a), F.A.C., no annual operating report shall be required for any facility operating under an air general permit.

(3) The annual operating report shall be submitted to the appropriate Department of Environmental Protection (DEP) division, district or DEP-approved local air pollution control program office by March 1 of the following year.

(4) Beginning with 2007 annual emissions, emissions shall be computed in accordance with the provisions of subsection 62-210.370(2), F.A.C., for purposes of the annual operating report.

[Rule 62-210.370, F.A.C.]

STANDARD TESTING REQUIREMENTS

Unless otherwise specified in the permit, the following testing requirements apply to all emissions units at the facility.

COMPLIANCE TESTING REQUIREMENTS

1. 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 two complete runs as proof of compliance, provided that the arithmetic mean of the two complete runs is at least 20% below the allowable emission limiting standard. [Rule 62-297.310(1), F.A.C.]

2. Operating Rate During Testing: Testing of emissions shall be conducted with the emissions unit operating at permitted capacity. If it is impractical to test at permitted capacity, an emissions unit may be tested at less than the maximum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test rate until a new test is conducted. Once the 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. Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. [Rule 62-297.310(2), F.A.C.]

3. Calculation of Emission Rate: For each emissions performance test, the indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the three separate test runs unless otherwise specified in a particular test method or applicable rule. [Rule 62-297.310(3), F.A.C.]

4. 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:

         (a) For batch, cyclical processes, or other operations which are normally completed within less than the minimum observation period and do not recur within that time, the period of observation shall be equal to the duration of the batch cycle or operation completion time.

         (b) The observation period for special opacity tests that are conducted to provide data to establish a surrogate standard pursuant to Rule 62-297.310(5)(k), F.A.C., Waiver of Compliance Test Requirements, shall be established as necessary to properly establish the relationship between a proposed surrogate standard and an existing mass emission limiting standard.

         (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 or test method, the minimum sample volume per run shall be 25 dry standard cubic feet.

c. *Calibration of Sampling Equipment.* Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1, F.A.C.

d. *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.]

5. 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.]

6. Sampling Facilities: The permittee shall install permanent stack sampling ports and provide sampling facilities that meet the requirements of Rule 62-297.310(6), F.A.C. Sampling facilities include sampling ports, work platforms, access to work platforms, electrical power, and sampling equipment support. All stack sampling facilities must also comply with all applicable Occupational Safety and Health Administration (OSHA) Safety and Health Standards described in 29 CFR Part 1910, Subparts D and E.

a. *Permanent Test Facilities.* The owner or operator of an emissions unit for which a compliance test, other than a visible emissions test, is required on at least an annual basis, shall install and maintain permanent stack sampling facilities.

b. *Temporary Test Facilities.* The owner or operator of an emissions unit that is not required to conduct a compliance test on at least an annual basis may use permanent or temporary stack sampling facilities. If the owner chooses to use temporary sampling facilities on an emissions unit, and the Department elects to test the unit, such temporary facilities shall be installed on the emissions unit within 5 days of a request by the Department and remain on the emissions unit until the test is completed.

c. *Sampling Ports.*

(1) All sampling ports shall have a minimum inside diameter of 3 inches.

(2) The ports shall be capable of being sealed when not in use.

(3) The sampling ports shall be located in the stack at least 2 stack diameters or equivalent diameters downstream and at least 0.5 stack diameter or equivalent diameter upstream from any fan, bend, constriction or other flow disturbance.

(4) For emissions units for which a complete application to construct has been filed prior to December 1, 1980, at least two sampling ports, 90 degrees apart, shall be installed at each sampling location on all circular stacks that have an outside diameter of 15 feet or less. For stacks with a larger diameter, four sampling ports, each 90 degrees apart, shall be installed. For emissions units for which a complete application to construct is filed on or after December 1, 1980, at least two sampling ports, 90 degrees apart, shall be installed at each sampling location on all circular stacks that have an outside diameter of 10 feet or less. For stacks with larger diameters, four sampling ports, each 90 degrees apart, shall be installed. On horizontal circular ducts, the ports shall be located so that the probe can enter the stack vertically, horizontally or at a 45 degree angle.

(5) On rectangular ducts, the cross sectional area shall be divided into the number of equal areas in accordance with EPA Method 1. Sampling ports shall be provided which allow access to each sampling point. The ports shall be located so that the probe can be inserted perpendicular to the gas flow.

d. *Work Platforms.*

(1) Minimum size of the working platform shall be 24 square feet in area. Platforms shall be at least 3 feet wide.

(2) On circular stacks with 2 sampling ports, the platform shall extend at least 110 degrees around the stack.

(3) On circular stacks with more than two sampling ports, the work platform shall extend 360 degrees around the stack.

(4) All platforms shall be equipped with an adequate safety rail (ropes are not acceptable), toe board, and hinged floor-opening cover if ladder access is used to reach the platform. The safety rail directly in line with the sampling ports shall be removable so that no obstruction exists in an area 14 inches below each sample port and 6 inches on either side of the sampling port.

e. *Access to Work Platform.*

(1) Ladders to the work platform exceeding 15 feet in length shall have safety cages or fall arresters with a minimum of 3 compatible safety belts available for use by sampling personnel.

(2) Walkways over free-fall areas shall be equipped with safety rails and toe boards.

f. *Electrical Power.*

(1) A minimum of two 120-volt AC, 20-amp outlets shall be provided at the sampling platform within 20 feet of each sampling port.

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

g. *Sampling Equipment Support.*

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

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

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

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

(2) A complete monorail or dual rail arrangement may be substituted for the eyebolt and bracket.

(3) When the sample ports are located in the top of a horizontal duct, a frame shall be provided above the port to allow the sample probe to be secured during the test.

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

7. 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.*

1. The owner or operator of a new or modified emissions unit that is subject to an emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining an operation permit for such emissions unit.

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 and/or solid 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 sub-subparagraph 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 and/or solid 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) 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 and/or solid fuel, other than during startup, for a total of more than 400 hours.

6. For fossil fuel steam generators on a semi-annual particulate matter emission compliance testing schedule, a compliance test shall not be required for any six-month period in which liquid and/or solid fuel is not burned for more than 200 hours other than during startup.

7. For emissions units electing to conduct particulate matter emission compliance testing quarterly pursuant to paragraph 62-296.405(2)(a), F.A.C., a compliance test shall not be required for any quarter in which liquid and/or solid fuel is not burned for more than 100 hours other than during startup.

8. Any combustion turbine that does not operate for more than 400 hours per year shall conduct a visible emissions compliance test once per each five-year period, coinciding with the term of its air operation permit.

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.

10. An annual compliance test conducted for visible emissions shall not be required for units exempted from air permitting pursuant to subsection 62-210.300(3), F.A.C.; units determined to be insignificant pursuant to subparagraph 62-213.300(2)(a)1., F.A.C., or paragraph 62-213.430(6)(b), F.A.C.; or units permitted under the General Permit provisions in paragraph 62-210.300(4)(a) or Rule 62-213.300, F.A.C., unless the general permit specifically requires such testing.

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 shall 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 paragraph 62-297.310(7)(b), F.A.C., shall apply.

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

RECORDS AND REPORTS

8. 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 on the results of each such test.
   b. The required test report shall be filed with the Department 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 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.
      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.

[Rule 62-297.310(8), F.A.C.]

SUMMARY OF FINAL BACT DETERMINATIONS

PROJECT DESCRIPTION

Buckeye operates an existing dissolving grade Kraft sulfate process pulp mill (SIC No. 2611) in Perry, Florida. This site is in an area that is in attainment (or designated as unclassifiable) for each air pollutant subject to a state or federal Ambient Air Quality Standard (NAAQS). The goal of the Foley Energy Independence Project is to improve efficiency for steam and electrical equipment at the plant, reduce the amount of electricity purchased from the grid and reduce the amount of purchased fossil fuels. Currently, the mill purchases approximately 120,000 MW-hours per year of electricity and approximately 6 million MMBtu per year of fuels. The project consists of the following major changes.

- The existing Nos. 2 and 3 Recovery Boilers (EU-006 and EU-007) will be physically modified and converted from direct contact evaporator units to low-odor, non-direct contact evaporator units. After completing the recovery boiler conversions, the black liquor oxidation system will be permanently shutdown. There will be miscellaneous changes to the common systems shared by the existing units such as piping, ductwork, pumps, tanks, etc.
- Two new forced-circulation/crystallizer black liquor concentrators and a new black liquor storage tank will be added to the existing multiple effect evaporator system (EU-046). The new concentrators will increase the solids content of the BLS from approximately 50% to 72%. Increased non-condensable gases generated from the multiple effect evaporator system will be controlled by combustion in the No. 1 Bark Boiler (primary control) or the No. 1 Power Boiler (secondary control), which also controls TRS emissions with a white liquor pre-scrubber.
- A new 28 MW condensing steam turbine-electrical generator will be installed to take advantage of the equipment efficiency improvements and approximately 13% additional bark/wood firing (annual basis) in the Nos. 1 and 2 Bark Boilers. Only 12 MW are expected to be generated as a result of this project. Future steam improvement projects may take advantage of the additional capacity. No physical changes or changes in the method of operation for the Bark Boilers are necessary to meet this goal. After completing the installation, the steam header pressure will then be controlled by modulating the steam flow to the condensing steam turbine instead of varying the firing rates of the power and bark boilers, which is the current practice. This means that the Bark Boilers can become based loaded units while firing bark/wood and less fossil fuel will be needed, which is currently fired as necessary to control the steam header pressure.
- Based on the equipment efficiency improvements and shift to bark/wood, the No. 2 Power Boiler (EU-003) will be restricted to firing only natural gas. No other changes are proposed for this unit.

Based on a netting analysis including other contemporaneous projects, this project is subject to preconstruction review for the prevention of significant deterioration (PSD) of air quality for emissions of carbon monoxide (CO), nitrogen oxides (NO_X), particulate matter (PM), and PM with an aerodynamic mean diameter equal to or less than 10 microns (PM_{10}) in accordance with Rule 62-212.400, F.A.C.

SUMMARY OF BACT DETERMINATIONS

In accordance with Rule 62-212.400(2), F.A.C., the permittee conducted a PSD netting analysis that compared baseline actual emissions with projected actual emissions. Based on the analysis, the project is subject to PSD preconstruction review for CO, NO_X, PM and PM_{10}. The Nos. 2 and 3 Recovery Boilers were the only units being modified or constructed that emit these PSD-significant pollutants. Therefore, the Department determined the Best Available Control Technology (BACT) for CO, NO_X, PM and PM_{10} emissions from the Nos. 2 and 3 Recovery Boilers. The provisions regulating PM emissions will serve as a surrogate for controlling PM_{10} emissions. The following tables summarize the BACT determinations.

No. 2 Recovery Boiler

Pollutant	BACT Standards	Control Technology Basis	Monitoring
CO [a]	400.0 ppmvd @ 8% O_2 and 214.1 lb/hour based on a 30-day rolling average	Boiler Design and Operation	CEMS
NO_X [a]	80.0 ppmvd @ 8% O_2 and 70.4 lb/hour based on a 30-day rolling average	Boiler Design and Operation	CEMS
Opacity [b]	20% based on 6-minute averages	Electrostatic Precipitator	COMS and EPA Method 9

Pollutant	BACT Standards	Control Technology Basis	Monitoring
PM	0.030 grains/dscf @ 8% O_2 and 31.6 lb/hour	Electrostatic Precipitator	EPA Method 5 Annual Tests

No. 3 Recovery Boiler

Pollutant	BACT Standards	Control Technology	Monitoring
CO [a]	400.0 ppmvd @ 8% O_2 and 208.0 lb/hour based on a 30-day rolling average	Boiler Design and Operation	CEMS
NO_X [a]	80.0 ppmvd @ 8% O_2 and 68.3 lb/hour based on a 30-day rolling average	Boiler Design and Operation	CEMS
Opacity [b]	20% based on 6-minute averages	Electrostatic Precipitator	COMS and EPA Method 9
PM	0.030 grains/dscf @ 8% O_2 and 30.7 lb/hour	Electrostatic Precipitator	EPA Method 5 Annual Tests

a. The CO and NO_X standards are based on a 30-day rolling CEMS average excluding emissions data collected during startup and shutdown.

b. The opacity standard applies once the electrostatic precipitator is placed in service during startup.

The Department's technical review and rationale for the BACT determinations are presented in the Technical Evaluation and Preliminary Determination issued concurrently with the draft permit and the Final Determination issued concurrently with the final PSD air construction permit.

STANDARD CONTINUOUS EMISSIONS MONITORING REQUIREMENTS

The Nos. 2 and 3 Recovery Boilers (EU-006 and EU-007) are subject to the following requirements for the new continuous emissions monitoring systems (CEMS). The permit requires compliance with the CO and NO_X emissions standards to be demonstrated continuously with data collected from a certified CEMS.

CEMS OPERATION PLAN

1. CEMS Operation Plan: The permittee shall create and implement a plan for the proper installation, calibration, maintenance, and operation of each CEMS required by this permit. The permittee shall submit the CEMS Operation Plan to the Bureau of Air Monitoring and Mobile Sources for approval prior to CEMS installation. The CEMS Operation Plan shall become effective 60 days after submittal or upon its approval. If the CEMS Operation Plan is not approved, the permittee shall submit a new or revised plan for approval. If the existing CO CEMS will be used, the permittee shall submit the CO CEMS Operation Plan along with the NO_X CEMS Operation Plan. *{Permitting Note: The Department maintains both guidelines for developing a CEMS Operation Plan and example language that can be used as the basis for the facility-wide plan required by this permit. Contact the Emissions Monitoring Section of the Bureau of Air Monitoring and Mobile Sources at 850/488-0114.}* [Rule 62-4.070(3), F.A.C.]

MONITORS, PERFORMANCE SPECIFICATIONS AND QUALITY ASSURANCE

2. Installation: All CEMS shall be installed such that representative measurements of emissions or process parameters from the facility are obtained. The owner or operator shall locate the CEMS by following the procedures contained in the applicable performance specification in Appendix B of 40 CFR 60.

3. Span Values and Dual Range Monitors: The permittee shall set appropriate span values for the CEMS based on the emissions standards and range of operation. If necessary, the permittee shall install dual range monitors in accordance with the CEMS Operation Plan. [Rule 62-4.070(3), F.A.C.]

4. Diluent Monitor: Because of the permit requirement to correct the CEMS output to the oxygen concentrations specified in the applicable emissions standard, the permittee shall maintain the existing oxygen (O_2) monitors. [Rule 62-4.070(3), F.A.C.]

5. Moisture Correction: If necessary, the permittee shall install a system to determine the moisture content of the exhaust gas and develop an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). [Rule 62-4.070(3), F.A.C.]

6. Continuous Flow Monitor: For compliance with mass emission flow rate standards, the permittee shall install a continuous flow monitor to determine the stack exhaust flow rate. The flow monitor shall be certified pursuant to 40 CFR Part 60, Appendix B, Performance Specification 6. Alternatively, the permittee may install a fuel flow monitor and use an appropriate F-Factor computational approach to calculate the stack exhaust flow rate. *{Permitting Note: The CEMS Operation Plan will contain additional details and procedures for monitor installation.}* [Rule 62-4.070(3), F.A.C.]

7. Performance Specifications: The permittee shall evaluate the "acceptability" of each CEMS by conducting the appropriate performance specification. CEMS determined to be "unacceptable" shall not be considered "installed" for purposes of meeting the timelines of this permit. For CO monitors, the permittee shall conduct Performance Specification 4 of 40 CFR Part 60, Appendix B. For NO_X monitors, the permittee shall conduct Performance Specification 2 of 40 CFR Part 60, Appendix B. [Rule 62-4.070(3), F.A.C.]

8. Quality Assurance: The permittee shall follow the quality assurance procedures of 40 CFR Part 60, Appendix F. For CO, the required relative accuracy test audit (RATA) tests shall be performed using EPA Method 10 in Appendix A of 40 CFR Part 60. For NO_X, the RATA tests shall be performed using EPA Method 7E in Appendix A of 40 CFR Part 60. [Rule 62-4.070(3), F.A.C.]

CALCULATION APPROACH FOR SIP COMPLIANCE

9. CEMS for Compliance: Once adherence to the applicable performance specification for each CEMS is demonstrated, the permittee shall use the CEMS to demonstrate compliance with the applicable emission standards as specified by this permit. [Rules 62-212.400(PSD-BACT) and 62-4.070(3), F.A.C.]

10. CEMS Data: Each CEMS shall monitor and record emissions during all operations and whenever emissions are being

generated, including during episodes of startups, shutdowns, and malfunctions. All data shall be used, except for invalid measurements taken during monitor system breakdowns, repairs, calibration checks, zero adjustments, and span adjustments. [Rule 62-4.070(3), F.A.C.]

11. Operating Hours and Operating Days: For purposes of this Appendix, the following definitions shall apply. An hour is the 60-minute period beginning at the top of each hour. Any hour during which an emissions unit is in operation for more than 15 minutes is an operating hour for that emission unit. A day is the 24-hour period from midnight to midnight. Any day with at least one operating hour for an emissions unit is an operating day for that emission unit. [Rule 62-4.070(3), F.A.C.]

12. Valid Hourly Averages: Each CEMS shall be designed and operated to sample, analyze, and record data evenly spaced over the hour at a minimum of one measurement per minute. All valid measurements collected during an hour shall be used to calculate a 1-hour block average that begins at the top of each hour.

    a. Hours that are not operating hours are not valid hours.

    b. For each operating hour, the 1-hour block average shall be computed from at least two data points separated by a minimum of 15 minutes. If less than two such data points are available, there is insufficient data, the 1-hour block average is not valid, and the hour is considered as "monitor unavailable."

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

13. Calculation Approaches: Compliance with the 30-day rolling CO and NO_X averages shall be determined after each operating day by calculating and recording the arithmetic average of all valid hourly averages for the previous 30 operating days (compliance period). As specified in the permit, limited amounts of CEMS data collected during startup and shutdown may be excluded from the compliance period. [Rules 62-212.400(PSD-BACT) and 62-4.070(3), F.A.C.]

14. Minimum Valid Hours: At least one valid hourly average shall be used to calculate the emissions over any averaging period specified by this permit. One valid hourly average shall be sufficient to calculate the emissions over any averaging period. [Rule 62-4.070(3), F.A.C.]

MONITOR AVAILABILITY

15. Monitor Availability: Monitor availability shall be calculated on a quarterly basis for each emission unit as the number of valid hourly averages obtained by the CEMS, divided by the number of operating hours, times 100%. The monitor availability calculation shall not include periods of time where the monitor was functioning properly, but was unable to collect data while conducting a mandated quality assurance/quality control activity such as calibration error tests, RATA, calibration gas audit, or relative accuracy audits (RAA). Monitor availability for each CEMS shall be 95% or greater in any calendar quarter. Monitor availability shall be reported in the quarterly excess emissions report. In the event 95% availability is not achieved, the permittee shall provide the Department with a report identifying the problems in achieving 95% availability and a plan of corrective actions that will be taken to achieve 95% availability. The permittee shall implement the reported corrective actions within the next calendar quarter. Failure to take corrective actions or continued failure to achieve the minimum monitor availability shall be violations of this permit. [Rule 62-4.070(3), F.A.C.]

EXCESS EMISSIONS

16. Definitions:

    a. *Excess Emissions* (under the Florida SIP) are defined as emissions of pollutants in excess of those allowed by any applicable air pollution rule of the Department, or by a permit issued pursuant to any such rule or Chapter 62-4, F.A.C. The term applies only to conditions which occur during startup, shutdown, or malfunction.

    b. *Startup* is defined as the commencement of operation of any emissions unit which has shut down or ceased operation for a period of time sufficient to cause temperature, pressure, chemical or pollution control device imbalances, which result in excess emissions.

    c. *Shutdown* means the cessation of the operation of an emissions unit for any purpose.

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

[Rule 62-210.200(Definitions), F.A.C.]

17. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. All such preventable emissions shall be included in any compliance determinations based on CEMS data. [Rules 62-210.700(4) and 62-4.070(3), F.A.C.]

18. Data Exclusion for SIP Compliance: As per the procedures in this condition, limited amounts of CO and NO_X CEMS emissions data may be excluded from the corresponding compliance demonstration, provided that best operational practices to minimize emissions are adhered to and the duration of data excluded is minimized. The limited amounts of data authorized for exclusion are specified in each corresponding permit subsection. As provided by the authority in Rule 62-210.700(5), F.A.C., the following conditions replace the provisions in Rule 62-210.700(1), F.A.C.

    a. *Excess Emissions.* For purposes of SIP-based permit limits, limited amounts of excess emissions data collected during periods of startup and shutdown may be excluded from compliance calculations as allowed by the permit standards.

    b. *Limiting Data Exclusion.* If the compliance calculation using all valid CEMS emission data (as defined in this Appendix) indicates that the emission unit is in compliance, then no CEMS data shall be excluded from the compliance demonstration.

    c. *Event Driven Exclusion.* The excess emissions must occur due to an underlying event (startup or shutdown). If there is no underlying event, then no data may be excluded.

    d. *Continuous Exclusion.* Data shall be excluded on a continuous basis per event. Data from discontinuous periods shall not be excluded for the same underlying event.

    e. *Reporting Excluded Data.* These procedures for excluding SIP-based excess emissions from compliance calculations are not necessarily the same procedures used for "excess emissions" as defined by federal rules. Semiannual reports required by this permit shall indicate the duration of data excluded from SIP compliance calculations.

The Excess Emissions Rule at Rule 62-210.700, F.A.C., cannot vary any requirement of a NSPS or NESHAP provision. [Rules 62-212.400(PSD-BACT) and 62-210.700, F.A.C.]

19. Notification Requirements: The permittee shall notify the Compliance Authority within one working day of discovering any emissions that demonstrate non-compliance for a given averaging period. [Rule 62-4.130, F.A.C.]

CALCULATING AND REPORTING ANNUAL EMISSIONS

20. CEMS for Calculating Annual Emissions: As defined by this Appendix, all valid data shall be used when calculating annual emissions.

    a. Annual emissions shall include data collected during startup, shutdown, and malfunction periods.

    b. Annual emissions shall include data collected during periods when the emission unit is not operating, but emissions are being generated (for example, firing fuel to warm up a process for some period of time prior to the emission unit's "official" startup).

    c. Annual emissions shall not include data from periods of time where the monitor was functioning properly, but was unable to collect data while conducting a mandated quality assurance/quality control activity such as calibration error tests, RATA, calibration gas audit, or RAA. These periods of time shall be considered "missing data" for purposes of calculating annual emissions.

    d. Annual emissions shall not include data from periods of time when emissions are in excess of the calibrated span of the CEMS. These periods of time shall be considered "missing data" for purposes of calculating annual emissions.

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

21. Accounting for Missing Data: All valid measurements collected during each hour shall be used to calculate a 1-hour block average that begins at the top of each hour. For each hour, the 1-hour block average shall be computed from at least two data points separated by a minimum of 15 minutes. If less than two such data points are available, the permittee shall account for emissions during that hour using site-specific data to generate a reasonable estimate of the 1-hour block average. [Rule 62-4.070(3), F.A.C.]

22. Emissions Calculation: Annual emissions shall be calculated as the sum of all valid emissions occurring during the year. [Rules 62-212.400(PSD) and 62-4.070(3), F.A.C.]

23. Reporting Annual Emissions: The permittee shall use data from each required CEMS when calculating annual emissions for purposes of computing actual emissions, baseline actual emissions, and net emissions increase, as defined at Rule 62-210.200, F.A.C., and for purposes of computing emissions pursuant to the reporting requirements of Rules 62-210.370(3) and 62-212.300(1)(e), F.A.C. [Rules 62-212.400(PSD) and 62-4.070(3), F.A.C.]

ON-SPECIFICATION USED OIL REQUIREMENTS

The permittee shall comply with the following requirements for on-specification used oil.

1. Upon request from the Department, a certification shall be provided that the on-specification used oil (prior to blending with fuel oil for firing) complies with the limits listed below.

   a. "On-specification" used oil is defined as used oil that meets the specifications of 40 CFR 279 (Standards for the Management of Used Oil) as listed below.

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

   Used oil which fails to comply with any of these specification levels is considered "off-specification" used oil. The firing of off-specification used oil at this facility is prohibited.

   b. Used oil containing a PCB concentration of 50 ppm or more shall not be fired at this facility and shall not be blended to meet this requirement.

   c. On-specification used oil with a PCB concentration of 2 ppm to less than 50 ppm shall be fired only at normal unit operating temperatures and shall not be fired during periods of startup or shutdown.

   d. On-specification used oil with a PCB concentration of 2 ppm or less may be fired at any time.

   e. On-specification used oil shall meet the maximum sulfur content specified in the permit.

   [40 CFR 279.61]

2. Generator: The on-specification used oil fired shall be generated at this facility.

3. Sampling and Analysis:

   a. Sampling and analysis shall be performed using approved methods specified in latest edition of EPA Publication SW-846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods.

   b. If the analytical results show that the used oil does not meet the specifications for on-specification used oil, or that it contains a PCB concentration of 50 ppm or greater, the owner or operator shall immediately cease firing the used oil. The owner or operator shall also immediately notify the appropriate Compliance Authority of the analytical results and indicate the proposed means of disposal of the used oil.

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

2. Used Oil Recordkeeping Required: The owner or operator shall obtain, make, and keep the following records related to the use of used oil in a form suitable for inspection at the facility by the Compliance Authority:

   a. Within 15 days following each calendar month, record the gallons of on-specification used oil blended with the No. 6 fuel oil during the previous calendar month and the previous 12 calendar months.

   b. Results of any sampling/analyses conducted.

   [Rule 62-4.070(3), F.A.C.; 40 CFR 279.61; and, 40 CFR 761.20(e)]

3. Used Oil Reporting Required: Within 30 days following each calendar quarter, the owner or operator shall submit to the appropriate Compliance Authority, any analytical results and the total amount of on-specification used oil blended with the No. 6 fuel oil during the quarter. [Rule 62-4.070(3), F.A.C.; 40 CFR Parts 279 and 761]

Walker, Elizabeth (AIR)

From: . Exchange Administrator
Sent: Monday, July 07, 2008 6:40 PM
To: Walker, Elizabeth (AIR)
Subject: Delivery Status Notification (Relay)
Attachments: ATT493179.txt; Notification of Revised Draft Permit Issuance: BUCKEYE FLORIDA, LIMITED PARTNERSHIP; 1230001-023-AC

This is an automatically generated Delivery Status Notification.

Your message has been successfully relayed to the following recipients, but the requested delivery status notifications may not be generated by the destination.

Howard_Drew@BKITECH.COM
Dave_Weeden@bkitech.com
Ray_Perry@BKITECH.COM

Walker, Elizabeth (AIR)

From: Exchange Administrator
Sent: Monday, July 07, 2008 6:40 PM
To: Walker, Elizabeth (AIR)
Subject: Delivery Status Notification (Relay)
Attachments: ATT493159.txt; Notification of Revised Draft Permit Issuance: BUCKEYE FLORIDA, LIMITED PARTNERSHIP; 1230001-023-AC

This is an automatically generated Delivery Status Notification.

Your message has been successfully relayed to the following recipients, but the requested delivery status notifications may not be generated by the destination.

dee_morse@nps.gov

Walker, Elizabeth (AIR)

From: Buff, Dave [DBuff@GOLDER.com]
To: undisclosed-recipients
Sent: Monday, July 07, 2008 7:37 PM
Subject: Read: Notification of Revised Draft Permit Issuance: BUCKEYE FLORIDA, LIMITED PARTNERSHIP; 1230001-023-AC

Your message

To: DBuff@GOLDER.com
Subject:

was read on 7/7/2008 7:37 PM.

Walker, Elizabeth (AIR)

From: Mail Delivery System [MAILER-DAEMON@mseive01.rtp.epa.gov]
Sent: Monday, July 07, 2008 6:40 PM
To: Walker, Elizabeth (AIR)
Subject: Successful Mail Delivery Report
Attachments: Delivery report; Message Headers

This is the mail system at host mseive01.rtp.epa.gov.

Your message was successfully delivered to the destination(s) listed below. If the message was delivered to mailbox you will receive no further notifications. Otherwise you may still receive notifications of mail delivery errors from other systems.

The mail system

<Forney.Kathleen@epamail.epa.gov>: delivery via 127.0.0.1[127.0.0.1]:10025: 250 OK, sent 48729B59_13379_447681_1 3951444461

Walker, Elizabeth (AIR)

From: Mail Delivery System [MAILER-DAEMON@sophos.golder.com]
Sent: Monday, July 07, 2008 6:40 PM
To: Walker, Elizabeth (AIR)
Subject: Successful Mail Delivery Report
Attachments: Delivery report; Message Headers

This is the mail system at host sophos.golder.com.

Your message was successfully delivered to the destination(s) listed below. If the message was delivered to mailbox you will receive no further notifications. Otherwise you may still receive notifications of mail delivery errors from other systems.

The mail system

<dbuff@golder.com>: delivery via 127.0.0.1[127.0.0.1]:10025: 250 OK, sent
48729B58_2609_98_1 77BA410EB774

Walker, Elizabeth (AIR)

From: Kirts, Christopher
To: Walker, Elizabeth (AIR)
Sent: Tuesday, July 08, 2008 8:25 AM
Subject: Read: Notification of Revised Draft Permit Issuance: BUCKEYE FLORIDA, LIMITED PARTNERSHIP; 1230001-023-AC

Your message

To: Howard Drew; Dave Weeden; 'Ray Perry'; Mr. David A. Buff, P.E., Golder Associates, Inc.
Cc: Kirts, Christopher; 'Forney.Kathleen@epamail.epa.gov'; 'dee_morse@nps.gov'; Mitchell, Bruce
Subject: Notification of Revised Draft Permit Issuance: BUCKEYE FLORIDA, LIMITED PARTNERSHIP; 1230001-023-AC
Sent: 7/7/2008 6:40 PM

was read on 7/8/2008 8:25 AM.

Walker, Elizabeth (AIR)

From: Dave Weeden [Dave_Weeden@bkitech.com]
Sent: Tuesday, July 08, 2008 7:54 AM
To: Walker, Elizabeth (AIR)
Subject: RE: Notification of Revised Draft Permit Issuance: BUCKEYE FLORIDA, LIMITED PARTNERSHIP; 1230001-023-AC

This was received. Thanks!!

Dave Weeden
Environmental Program Manager
Buckeye Technologies, Inc.

(850) 584-1398

From: Walker, Elizabeth (AIR) [mailto:Elizabeth.Walker@dep.state.fl.us]
Sent: Monday, July 07, 2008 6:40 PM
To: Howard Drew; Dave Weeden; Ray Perry; Mr. David A. Buff, P.E., Golder Associates, Inc.
Cc: Kirts, Christopher; Forney.Kathleen@epamail.epa.gov; dee_morse@nps.gov; Mitchell, Bruce
Subject: Notification of Revised Draft Permit Issuance: BUCKEYE FLORIDA, LIMITED PARTNERSHIP; 1230001-023-AC

Please send a "reply" message verifying receipt of the attached document(s); this may be done by selecting "Reply" on the menu bar of your e-mail software and then selecting "Send". We must receive verification of receipt and your reply will preclude subsequent e-mail transmissions to verify receipt of the document(s).

This is the official notification of Revised Draft Permit Issuance for the following project:

Owner/Company Name: BUCKEYE FLORIDA, LIMITED PARTNERSHIP
Facility Name: BUCKEYE FLORIDA, LIMITED PARTNERSHIP
Project Number: 1230001-023-AC
Permit Status: REV DRAFT
Permit Activity: CONSTRUCTION
Facility County: TAYLOR

Processor: Bruce Mitchell

Link to Project Documents: http://ARM-PERMIT2K.dep.state.fl.us/adh/prod/pdf_permit_zip_files/1230001.023.AC.R_pdf.zip

The Bureau of Air Regulation is issuing electronic documents for permits, notices and other correspondence in lieu of hard copies through the United States Postal System, to provide greater service to the applicant and the engineering community. Access these documents by clicking on the link provided above, or search for other project documents using the "*Air Permit Documents Search*" website at http://www.dep.state.fl.us/air/eproducts/apds/default.asp .

The document(s) may require immediate action within a specified time frame. Please open and review the document(s) as soon as possible. Please advise this office of any changes to your e-mail address or that of the Engineer-of-Record. If you have any problems opening the documents or would like further information, please contact the Florida Department of Environmental Protection, Bureau of Air Regulation at (850)488-0114.

Walker, Elizabeth (AIR)

From: Walker, Elizabeth (AIR)
Sent: Monday, July 07, 2008 6:40 PM
To: 'Howard Drew'; 'Dave Weeden'; 'Ray Perry'; 'Mr. David A. Buff, P.E., Golder Associates, Inc.'
Cc: Kirts, Christopher; 'Forney.Kathleen@epamail.epa.gov'; 'dee_morse@nps.gov'; Mitchell, Bruce
Subject: Notification of Revised Draft Permit Issuance: BUCKEYE FLORIDA, LIMITED PARTNERSHIP; 1230001-023-AC

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The Bureau of Air Regulation is issuing electronic documents for permits, notices and other correspondence in lieu of hard copies through the United States Postal System, to provide greater service to the applicant and the engineering community. Access these documents by clicking on the link provided above, or search for other project documents using the "*Air Permit Documents Search*" website at http://www.dep.state.fl.us/air/eproducts/apds/default.asp .

The document(s) may require immediate action within a specified time frame. Please open and review the document(s) as soon as possible. Please advise this office of any changes to your e-mail address or that of the Engineer-of-Record. If you have any problems opening the documents or would like further information, please contact the Florida Department of Environmental Protection, Bureau of Air Regulation at (850)488-0114.

Thank you,

Elizabeth Walker
Bureau of Air Regulation
(850)921-9505

Tracking:

Recipient	Delivery	Read
'Howard Drew'		
'Dave Weeden'		
'Ray Perry'		
'Mr. David A. Buff, P.E., Golder Associates, Inc.'		
Kirts, Christopher	Delivered: 7/7/2008 6:40 PM	Read: 7/8/2008 8:25 AM
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'dee_morse@nps.gov'		
Mitchell, Bruce	Delivered: 7/7/2008 6:40 PM	