Memorandum

Florida Department of Environmental Protection

To: Joe Kahn, Division of Air Resource Management

Through: Trina Vielhauer, Bureau of Air Regulation

Through: Jeff Koerner, New Source Review Section SA for

From: Bruce Mitchell, New Source Review Section RM

Date: August 18, 2008

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

The Department distributed an "Intent to Issue Permit" package on July 7, 2008. The applicant published the "Public Notice of Intent to Issue" in the Perry News-Herald/Taco Times on July 11, 2008. No petitions for administrative hearings or extensions of time to petition for an administrative hearing were filed. There were no comments received during the Public Notice period.

I recommend your approval of the attached Final Permit for this project.

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

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.

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Joseph Kahn, Director
Division of Air Resource Management

8/21/08
Effective Date

PERMITTEE

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

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

PROJECT

Air PSD Permit No. PSD-FL-397
Project No. 1230001-023-AC
Foley Mill in Perry

The project 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 the existing Foley Mill, which is located in Taylor County at One Buckeye Drive in Perry, Florida.

NOTICE AND PUBLICATION

The Department distributed an "Intent to Issue Permit" package on July 7, 2008. The applicant published the "Public Notice of Intent to Issue" in the Perry News-Herald/Taco Times on July 11, 2008. No petitions for administrative hearings or extensions of time to petition for an administrative hearing were filed. There were no comments received during the Public Notice period.

CONCLUSION

The final action of the Department is to issue the permit as described above.

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

NOTICE OF PERMIT

In the Matter of an
Application for Permit by:

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
Foley Mill
Foley Energy Independence Project

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. 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. This permit is issued pursuant to Chapter 403, Florida Statutes (F.S.).

Any party to this order has the right to seek judicial review of it under Section 120.68, F.S., by filing a notice of appeal under Rule 9.110 of the Florida Rules of Appellate Procedure with the clerk of the Department of Environmental Protection in the Office of General Counsel (Mail Station #35, 3900 Commonwealth Boulevard, Tallahassee, Florida, 32399-3000) and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The notice must be filed within 30 days after this order is filed with the clerk of the Department.

Executed in Tallahassee, Florida

Trina L Vielhauer 8/18/08

Trina Vielhauer, Chief (Date)
Bureau of Air Regulation

TLV/jfk/bm

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Notice of Permit (including the Final Permit) was sent by electronic mail with received receipt requested 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)
Ms. Catherine Collins, Fish and Wildlife Service (catherine_collins@fws.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.

(Clerk) 8/22/08 (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 megawatt-hours (MW-hours) per year of electricity and approximately 6,000,000 million British thermal units (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.]

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 electrostatic precipitator (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 the National Emission Standard for Hazardous Air Pollutants (NESHAP) Subpart MM and the General Provisions in Subpart A of Title 40 of the Code of Federal Regulations (CFR) Part 63.

   [Rule 62-296.404, F.A.C.; and NESHAP Subparts A and MM in 40 CFR Part 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 2,192 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 1,000 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 6,400 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 1,000 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 $feet^2$/1,000 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 $feet^2$/1,000 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 continuous emissions monitoring system (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 continuous opacity monitoring system (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.]

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

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. <u>Frequency of Compliance Tests</u>: 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.]

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]

Florida Department of
Environmental Protection
Marjory Stoneman Douglas Building
3900 Commonwealth Boulevard
Tallahassee, Florida 32399-3000

Charlie Crist
Governor

Jeff Kottkamp
Lt. Governor

Michael W. Sole
Secretary

May 28, 2008

RECEIVED
MAY 29 2008
BUREAU OF AIR REGULATION

Mr. Charles S. Aiken
Senior Vice President, Manufacturing
Buckeye Technologies Inc.
1001 Tillman, P.O. Box 80407
Memphis, Tennessee 38108-0407

Dear Mr.Aiken:

Thank you for your May 13, 2008, letter to Secretary Michael W. Sole regarding Buckeye Technologies Inc.'s (Buckeye) Energy Independence Project. Secretary Sole has asked that I respond to your concerns with the Florida Department of Environmental Protection's (DEP) permitting process.

DEP is committed to providing a timely review of permit applications and facilitating open communication with applicants. I would like to assure you that DEP's Division of Air Resource Management (Division) is dedicated to working with Buckeye on the review of this permit application.

A request for additional information was sent to Buckeye on January 10, 2008. Buckeye responded to this request on April 1, 2008. The emission calculations submitted with the application were not clear, and these calculations are central to the review of the project. Because Buckeye's response did not sufficiently address this issue, the Division sent a follow-up request for information on May 1, 2008.

On May 8, 2008, a representative with Buckeye, Mr. Andreu, discussed the permit application with the Division. During this discussion, the request for additional information was reviewed to ensure both the Division and Buckeye had a mutual understanding as to the specific information requested and the importance of this information in reviewing the permit application.

We look forward to meeting with Buckeye on June 17, 2008, in Tallahassee. However, I would encourage you to meet with the Division's technical staff prior to that meeting to discuss the additional information requested by the Division. If you have any questions or concerns prior to that meeting, please contact me at (850) 245-2036.

Sincerely,

Mimi Drew

Mimi Drew
Deputy Secretary, Regulatory Programs and Energy

cc: Michael W. Sole, Secretary, DEP
Joseph Kahn, Director, Division of Air Resource Management, DEP
Greg Strong, Director, Northeast District Office, DEP
Trina Vielhauer, Bureau Chief, Division of Air Resource Management, DEP
Chris Kirts, Air Program Administrator, Northeast District Office, DEP
Jeff Koerner, Professional Engineer, Division of Air Resource Management, DEP

Florida Department of Environmental Protection

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

May 27, 2008

Ms. Meredith Bond
United States Department of the Interior
U. S. Fish and Wildlife Service
National Wildlife Refuge System
Branch of Air Quality
7333 W. Jefferson Ave., Suite 375
Lakewood, CO 80235-2017

RE: Buckeye Florida Limited Partnership
Foley Independence Project RAI Response
1230001-023-AC - PSD-FL-397

Dear Ms. Bond:

Attached is your copy of the Buckeye Florida Limited Partnership's response to a request for additional information on the Foley Energy Independence project.. This project is being tracked under project number 1230001-023-AC (PSD FL 397) in the Tallahassee Permitting office.

Please email comments or questions on this project to the review engineer, Bruce Mitchell, at Bruce.Mitchell@dep.state.fl.us or call (850) 488-0114.

Sincerely,

Jeff Koerner, P.E., Administrator
New Source Review Permitting Section

JK/ew

Enclosure

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

May 27, 2008

Ms. Katy R. Forney
US EPA Region 4
Air Pollution Control Branch
61 Forsyth Street, SW
Atlanta GA 30303

RE: Buckeye Florida Limited Partnership
Foley Independence Project RAI Response
1230001-023-AC - PSD-FL-397

Dear Ms. Forney:

Attached is your copy of the Buckeye Florida Limited Partnership's response to a request for additional information on the Foley Energy Independence project.. This project is being tracked under project number 1230001-023-AC (PSD FL 397) in the Tallahassee Permitting office.

Please email comments or questions on this project to the review engineer, Bruce Mitchell, at Bruce.Mitchell@dep.state.fl.us or call (850) 488-0114.

Sincerely,

Jeff Koerner, P.E., Administrator
New Source Review Permitting Section

JK/ew

Enclosure

cc: file

EXPRESS

GND

FM: DEP AIR RESOURCE MGMT
E. Walker
DIRECTOR OFFICE STE 23
111 S MAGNOLIA DR
TALLAHASSEE, FL 32301
UNITED STATES Phone: 850-488-0114

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61 FORSYTH STREET, SW
AIR PERMIT SECTION
ATLANTA, GA 30303
UNITED STATES

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Phone#:	404-562-9130
Sent By:	E. Walker
Phone#:	850-488-0114

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Telephone (352) 336-5600
Fax (352) 336-6603
www.golder.com

Golder Associates

May 21, 2008

0738-7656

Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Attention: Mr. Jeffery Koerner, P.E.

**RE: BUCKEYE FLORIDA, LIMITED PARTNERSHIP
AIR PERMIT APPLICATION NO. 1230001-023-AC/PSD-FL-397
MODIFICATION TO THE NOS. 1 AND 2 POWER BOILERS, NOS. 1 AND 2 BARK BOILERS, NOS. 2 AND 3 RECOVERY BOILERS, AND PULPING SYSTEM
REQUEST FOR ADDITIONAL INFORMATION NO. 2**

Dear Mr. Koerner:

Buckeye Florida, Limited Partnership (Buckeye) has received the Department's (FDEP's) request for additional information (RAI) dated May 1, 2008, regarding the Foley Energy Independence Project. Each of the Department's requests is answered below, in the same order as they appear in the RAI letter.

Comment 1. As previously requested, please provide the details of the work to be performed on the Nos. 2 and 3 Recovery Boilers that will convert each unit to the Non-Direct Contact Evaporator design (ductwork, economizers, tubing, refractory, etc.)

Response 1: The Foley Energy Independence Project will convert the existing Nos. 2 and 3 Recovery Boilers to non-direct contact evaporator (NDCE) design from the existing direct contact evaporator (DCE) design. The objective of the project is to increase the system efficiency and increase the steam generation using the same fuel in the recovery boilers (i.e., black liquor, fuel oil, tall oil). The additional steam generated will be used to generate power in a new condensing turbine (CT) generator.

The quantity of black liquor solids fired in the two recovery boilers will not change from the existing firing rate. The improved efficiency will occur because the evaporation of the black liquor will no longer be accomplished using direct contact with flue gas at a 1:1 economy, but will be accomplished with external evaporation systems with a 4.2:1 economy. Also the heating value of the black liquor fuel will increase due to the elimination of black liquor oxidation. Black liquor oxidation causes partial oxidation of the liquor and a reduction of heating value of the fuel before it reaches the boilers.

To accomplish the project goals, the boilers will be modified and concentration systems will be added. When the direct contact evaporators are removed, additional will be contained in the flue gases entering the boilers. Therefore, additional heat transfer surface area will need to be added to the boilers to absorb the heat and produce steam. This will be accomplished by the installation of a new economizer on the No. 2 Recovery Boiler, which currently does not have an economizer, and installation of an additional economizer on the No. 3 Recovery Boiler, which currently has a small economizer, in order to increase the heat transfer surface area. Also, additional superheater surface area will be needed on both boilers to maintain steam temperature when the economizers are added.

No. 2 Recovery Boiler

The modifications on the No. 2 Recovery Boiler will include the following:

- Replacement or modification of the flue ducts from the generating section outlet to the cyclone evaporator outlet;
- Installation of a new economizer with new soot blowers;
- Increased superheater surface area;
- Installation of an ash collection system to collect the ash from the new economizer and ducts;
- Installation of a new mix tank in order to mix the ash into the black liquor; and
- Installation of a tertiary air fan.

Replacement/Modification of flue ducts – A new flue gas duct will be installed to connect the economizer inlet to the generating section outlet. New flue gas ducts will be installed from the economizer outlet to the cyclone evaporators. The cyclone evaporators will no longer function as evaporators, but will be modified and will function as flue gas ducts. The cyclone outlets will continue to be connected to the existing precipitator inlet.

No. 2 Recovery Boiler economizer – The new economizer for the No. 2 Recovery Boiler will be a horizontal economizer with approximately 68,500 linear feet of 2-inch diameter tubing. Also included in the economizer will be inlet and outlet headers for the feed water, casing, and support steel. Fifteen additional soot blowers will be added to the economizer to keep the surface area clean.

Additional superheater heat transfer surface area – Additional superheater heat transfer surface area will be added to maintain the steam temperature leaving the boiler at the same value as with the current operation. Maintaining superheater temperature is critical in order to optimize power generation in the condensing turbine generator. Eight additional rows of superheater tubes will be added for an increase in superheater surface area of approximately 20 percent.

Ash collection & Mix tanks – A new mix tank will be installed to allow mixing of the ash collected from the economizer and flue gas ducts. The tank will be 12 feet in diameter and 10 feet tall, with an overflow pipe at a height of 8.5 feet, resulting in a usable capacity of 7,200 gallons. Fifty-percent black liquor from an existing storage tank (east black liquor storage tank) will supply the existing No. 2 Recovery Boiler precipitator mix tank. This black liquor will be un-oxidized 50-percent black liquor as opposed to the 65-68 percent oxidized black liquor currently being supplied from the cyclone evaporator recirculation pumps. Black liquor in the precipitator mix tank will collect the ash from the precipitator and will flow by gravity to the new mix tank. The collected ash from the economizer and flue ducts will be conveyed by drag conveyors to the new mix tank. The black liquor in the new mix tank will be returned to the 50-percent black liquor storage tank after the ash is mixed into the liquor. A revised process flow diagram of the No. 2 Recovery Boiler, including the new mix tank and ash removal system, is provided in Figure 2-9 of Attachment A of this response.

Tertiary air fan – The additional heating value of the un-oxidized black liquor (approximately 7 percent) will require additional combustion air to be supplied to the boiler. The current combustion air fans are marginally sized, therefore additional combustion air capacity is required. A new tertiary air fan will supply ambient air to the boiler at the tertiary air elevation. The new tertiary air fan will be designed for approximately 123,000 pounds per hour (lb/hr), which will increase the total combustion air capacity by approximately 20 percent. This size fan is required, as all at the tertiary air elevation will be supplied by this fan.

Burners and burner pumps – No modifications will be made to the liquor burner pumps on the No. 2 Recovery Boiler, as the firing rate will be similar to the current black liquor firing rate. No modification will be made to the fossil fuel auxiliary burners, which will operate in the same capacity as they are currently operating.

No. 3 Recovery Boiler

The modifications to the No. 3 Recovery Boiler will be similar to the changes on the No. 2 Recovery Boiler, except for a few differences. Detailed technical information regarding the sizing of any new equipment for the No. 3 Recovery Boiler is currently unavailable, as the final engineering analysis is currently being performed, and the process of requesting quotes from manufacturers is also ongoing. The modifications to the No. 3 Recovery Boiler will include the following:

- Installation of an additional economizer;
- Installation of two new superheater platens;
- Installation of a new water coil air heater;
- Installation of new flue gas ducts; and
- Installation of a new ash collection system and a new ash mix tank to collect the ash from the new economizer and ducts.

No. 3 Recovery Boiler economizer – The No. 3 Recovery Boiler currently has a small economizer in service, which will remain in service as a result of this project. An additional economizer will be installed to recover the heat in the flue gases currently being used for evaporation in the cascade evaporator. The economizer will include additional heat transfer surface, inlet and outlet headers for the feed water, casing, and support steel. Also, additional soot blowers will be required, but the number of soot blowers is currently unknown.

Superheater platens – Two new superheater platens will be installed in the No. 3 Recovery Boiler superheater, which will increase the superheater heat transfer surface area by approximately 6 percent.

Water coil air heater – In addition to the installation of a new economizer, a new water coil air heater will be installed to preheat and increase the primary air temperature to the lower furnace of the No. 3 Recovery Boiler. This will reduce the temperature of the water leaving the new economizer before it enters the existing economizer. This change is required to prevent steam from being generated in the economizer (steaming economizer) which could cause vibration and boiler stability problems.

Installation of flue gas ducts – A new flue gas duct will be installed to connect the outlet of the existing economizer to the inlet of the new economizer. A new flue gas duct will also be installed from the outlet of the new economizer to the inlet of the existing electrostatic precipitator (ESP).

Ash collection & mix tanks – An ash collection system will be installed to collect the ash from the new economizer and flue gas ducts and mix the ash into the black liquor. The system on this boiler will be a sluice system where black liquor is pumped from the existing precipitator mix tank to sluice bowls located on the economizer and flue gas duct hopper outlets. Ash will mix with the black liquor in the sluice bowls and will return by gravity to the precipitator mix tank. A revised flow diagram of the proposed No. 3 Recovery Boiler, including the proposed ash sluice system, is provided in Figure 2-10 of Attachment A of this response.

Combustion air fans – The existing combustion air fans on the No. 3 Recovery Boiler are adequately sized to accommodate the increased heating value of the black liquor fuel, therefore no modifications are required for the fans.

Burners and burner pumps – No modifications will be made to the liquor burner pumps on the No. 3 Recovery Boiler, as the firing rate will be similar to the current black liquor firing rate. No modification will be made to the fossil fuel auxiliary burners, which will operate in the same capacity as they are currently operating.

Multiple Effect Evaporator (MEE) System

Because direct contact evaporation of black liquor using boiler flue gas will be eliminated, two new concentrator systems will be added to concentrate the black liquor to the appropriate concentration needed for firing in the boilers. The two concentrators, one for each recovery boiler, will be tied into an existing multiple effect black liquor evaporator. Each of the existing evaporator sets are five-effect units. The two concentrators will be identical in design, but each will operate at a slightly different rate based on the capability of the existing MEE unit that it is tied into.

Each concentrator will be a forced circulation/crystallizer type unit and will include the following:

- Two tube and shell heat exchangers;
- Two recirculation pumps;
- A crystallizer flash tank;
- A product flash tank; and
- A product transfer pump.

Steam will be supplied to the concentrator heat exchangers at a gauge pressure of 50 pounds per square inch (psi), and the concentrator will function as the first effect when tied to the existing evaporator train. The first and second effects of the existing evaporator will be tied together in a parallel configuration in the vapor flow path as opposed to the current series configuration. Therefore the two effects tied in parallel will become the second effect of the new concentrator/evaporator system. A revised flow diagram of the MEE system is provided in Figure 2-11 of Attachment A of this response.

Vapor from the concentrator crystallizer flash tank will supply the new system second effect (old first and second effects now in parallel). Vapor from the new system second effect will supply the existing third effect. The vapor flow path from the third effect to the condenser will remain the same as the current system.

Three external black liquor heaters will be added to each evaporator system to preheat liquor between effects. This additional heating surface for preheating black liquor will allow the internal heaters within the effects to be opened and function as evaporator surface area. An additional parallel auxiliary condenser will be added to the No. 3 black liquor evaporator to insure adequate condensing capacity. Miscellaneous piping and vapor duct changes will be required to tie in the new vapor flow and liquor flow configurations and to minimize vapor line pressure drop between effects. There may be minor pump upgrades to accommodate increased head requirements of the new design.

The new concentrator/evaporator systems will continue to operate with five-effect economy, with an expected economy of 4.2 pounds of evaporation per pound of steam supplied to the concentrator. The total evaporation capacity of the two new systems will be approximately 2 percent greater than the current total evaporation capacity of the two existing evaporator trains, the cyclone evaporator on the No. 2 Recovery Boiler, and the cascade evaporator on the No. 3 Recovery Boiler. The maximum black liquor solids throughput of the Nos. 2 and 3 MEEs will be 122,356 lb/hr and 127,350 lb/hr, respectively.

Comment 2. Describe in detail what is covered under "common system changes", as described in RAI response No. 2.c.1., last bullet. Regarding the reference to pumps, will there be any change-out of any fuel pumps? If yes, please provide a description and the displacement (gallons/hour) of the existing pump and the new pump.

Response 2: The common system items include project scope that is needed for both boilers. This includes an additional concentrated liquor storage tank with pumps and piping, pumps and piping to recover and mix boiler ash into the black liquor, and piping to allow transferring black liquor to the various tanks and equipment.

The operating concept on how to mix boiler ash with the black liquor will change significantly when the Foley Energy Independence Project is implemented. The storage of concentrated liquor and delivery of concentrated liquor to the recovery boilers will also change. There will be **NO CHANGE** to the black liquor fuel delivery to the burners (i.e. the boiler black liquor burner pumps supplying black liquor to the burners will not change on either recovery boiler).

Presently, the scope of "common system changes" includes the following items:

- Installation of a new concentrated black liquor storage tank;
- Installation of piping from the new concentrators to the new storage tank and/or the existing storage tank;
- Installation of piping from the concentrated liquor storage tanks to the recovery boiler salt cake mix tanks;
- Installation of a recirculation pump and piping on each concentrated liquor storage tank to minimize the potential for tank cone plugging;
- Installation of a transfer line between the new and existing concentrated liquor tanks;
- Installation of new pumps on the existing East 50-percent black liquor storage tank to circulate 50-percent liquor to the boilers for ash mixing; and
- Installation of pumps on the recovery boiler ash mix tanks to supply sluice systems and return the liquor to the East 50-percent storage tank.

When the Foley Energy Independence Project is implemented, the concentration of black liquor to the necessary firing concentration will no longer be coupled to recovery boiler operation. Black liquor concentration will occur in the concentrators, which will be coupled with evaporator operation. Therefore, concentrated black liquor storage is required to be able to operate the boilers when concentrator/evaporator systems are down for maintenance. The existing concentrated black liquor storage tank does not have enough surge capacity to allow the boilers to operate when a concentrator/evaporator system is down for routine maintenance or cleaning. A new concentrated black liquor storage tank will be added, sized such that the capacity of the existing tank and the new tank combined will allow the boilers to operate at full rate for up to 12 hours with one of the three 70-percent concentrator/evaporator systems (Nos. 2, 3, and 4 MEEs) down for maintenance.

Each concentrated black liquor storage tank will have three pumps. Two of the pumps will supply liquor to the boiler salt cake mix tanks and one pump will be dedicated to re-circulate liquor within the tank. The liquor transfer pumps (2 per tank) will each have a capacity of 332 gallons per minute (gpm). The recirculation pump (1 per tank) will have a capacity of 600 gpm. The normal expected operation is for the product from the existing No. 4 concentrator and the product from the new No. 3 concentrator to supply the existing concentrated liquor storage tank (West 70-percent storage tank) and for the new No. 2 concentrator to supply the new concentrated liquor storage tank (East 70-percent storage tank). The transfer pumps on the existing concentrated liquor storage tank (West

70-percent storage tank) will normally supply the No. 3 Recovery Boiler and the No. 4 Recovery Boiler (existing non-direct contact boiler) salt cake mix tanks. It is expected that both transfer pumps will normally be in operation. One transfer pump on the new concentrated liquor storage tank (East 70-percent storage tank) will supply liquor to the No. 2 Recovery Boiler. In addition, this pump will transfer a nominal amount of concentrated black liquor to the existing concentrated liquor storage tank (West 70-percent storage tank). The second pump will normally be down and will be available as an in-line spare. The recirculation pumps on each tank will circulate liquor from the side of the cone bottom and discharge into the bottom of the cone. This is expected to prevent solids from settling and collecting in the bottom of the cone.

The new operating concept for mixing boiler ash is to circulate 50-percent black liquor from the East 50-percent black liquor storage tank to the Nos. 2 and 3 Recovery Boilers to mix in the ash from the precipitators, economizer, generating section hoppers, and flue gas ducts. The liquor will be returned back to the East 50-percent black liquor storage tank. The two new concentrators will be supplied from the East 50-percent black liquor storage tank. This concept is being used because it is believed it is easier to mix the ash with the lower concentration liquor, and the forced circulation/crystallizer concentrators perform better if the liquor being evaporated contains suspended solids.

Two new pumps will be installed on the East 50-percent black liquor storage tank to be used in addition to the existing pumps to supply the concentrators and the boiler ash mix systems. One pump will have a capacity of 517 gpm, and the other pump will have a capacity of 300 gpm. Also, new piping will be installed for the supply of the concentrators and for the supply and return of liquor used in the boiler ash mix systems.

Fifty-percent black liquor from the East 50-percent black liquor storage tank will supply a new mix tank on the No. 2 Recovery Boiler. After ash has been mixed with the liquor, it will be returned to the East 50-percent black liquor storage tank. Two new pumps will be installed on the mix tank. Each pump will have a capacity of 300 gpm.

Fifty-percent black liquor from the East 50-percent black liquor storage tank will supply the existing precipitator mix tank on the No. 3 Recovery Boiler. Liquor will be supplied from the precipitator mix tank to the existing sluice hopper under the generating section and existing economizer of the boiler and to the sluice hoppers for the new economizer and flue gas ducts that are being added by the project. After ash has been mixed with the liquor, it will be returned to the East 50-percent black liquor storage tank. One new pump will be installed on the mix tank and two pumps will be upgraded. The new pump will have a capacity of 182 gpm, and the upgraded pumps will each have a capacity of 682 gpm. One of the upgraded pumps will be a stand-by pump. The smaller pump will return the liquor to the East 50-percent black liquor storage tank and the larger capacity pump will supply liquor to the multiple sluice points.

Comment 3. Regarding contemporaneous emission changes discussed in RAI response No. 5, your comment is confusing. What is the previous permit number that Permit No. 1230001-018-AC revised and you did not include because it was outside of the contemporaneous 5-year period? Please describe when each project was completed.

Response 3: The previous permit that Permit No. 1230001-018-AC revised is Permit No. 1230001-011-AC. Both of these permits contained tables with the net emissions changes based on the changes in the permit (see Attachment B). As shown, there were no changes in the total net emissions changes between Permit No. 1230001-011-AC and Permit No. 1230001-018-AC, except for values for total reduced sulfur (TRS) emissions. In Permit No. 1230001-011-AC there was a total net decrease in TRS emissions of 49.9 tons per year (TPY), while in Permit No. 1230001-018-AC there was a total net decrease in TRS emissions of 48.9 TPY. While there was a slight increase in TRS emissions from Permit No. 1230001-011-AC to Permit No. 1230001-018-AC, there was still a significant decrease in TRS emissions as a result of the project. The emissions increases of sulfur dioxide (SO_2) and sulfuric acid mist (SAM) resulting from this project were granted a Pollution Control Project (PCP) exclusion pursuant to Rule 62-212.400(2)(a)2.b., F.A.C. Therefore, these emissions were not included in the total contemporaneous emissions increases in Tables 3-3 and 3-4. The changes outlined in Permit No. 1230001-011-AC were implemented by the end of 2001 and the beginning of 2002, with the No. 1 Power Boiler (EU 002) operating as a secondary noncondensible gas (NCG) and TRS control device.

Another project completed recently (early 2006) that was not included in the contemporaneous emissions changes was the upgrade of the No. 2 Brownstock Washing System in order to comply with the Kraft pulping standards of 40 CFR Part 63, Subpart S (MACT I) under Permit No. 1230001-014-AC (see Attachment B). The project resulted in significant emissions increases in SO_2, nitrogen oxides (NO_x), carbon monoxide (CO), particulate matter (PM), particulate matter with a diameter of 10 microns or less (PM_{10}), and SAM. These emissions increases were also granted a PCP exclusion pursuant to Rule 62-212.400(2)(a)2.b., F.A.C. Therefore, these emissions were not included in the total contemporaneous emissions increases in Tables 3-3 and 3-4. The project also resulted in emission decreases in TRS and volatile organic compounds (VOC).

Tables 3-3 and 3-4 have been updated to reflect the emissions from Permit Nos. 1230001-018-AC and 1230001-014-AC; however, the PSD applicability analysis did not change as a result of these emissions, as described above. The updated Tables 3-3 and 3-4 have been included in Attachment C of this response.

Comment 4. **When the conversion of the No. 2 Recovery Boiler to low-odor design during Phase I is completed and a new black liquor concentrator installed, the total reduced sulfur (TRS) emissions collected by the noncondensible gas (NCG) system will increase, which will increase sulfur dioxide (SO_2) emissions when combusted. Why was the PSD netting analysis split into Phase I and Phase II? Why were the SO_2 emissions increases from the No. 1 Bark Boiler and No. 1 Power Boiler included in Phase II rather than Phase I?**

Response 4: The project has two phases and therefore the PSD applicability for each phase was assessed (i.e., determined whether the phase would result in a PSD significant emission rate increase in one or more pollutants). The changes in Phase I include conversion of the No. 2 Recovery Boiler from a DCE design to an NDCE design, and the installation of a new black liquor concentrator for the No. 2 Recovery Boiler. The changes in Phase II include conversion of the No. 3 Recovery Boiler from DCE design to NDCE design, installation of a new black liquor concentrator for the No. 3 Recovery Boiler, installation of a new condensing turbine generator, and increasing the amount of wood/bark purchased in order to increase the annual heat input to the Nos. 1 and 2 Bark Boilers. Therefore, both phases were evaluated separately for PSD applicability.

The increases in SO_2 emissions due to TRS and NCG destruction in the No. 1 Bark Boiler and the No. 1 Power Boiler were included in both Phase I and Phase II, however they were included under the heading of the black liquor concentrators. The purpose of this was to keep separate the emissions due to TRS/NCG burning and those due to fuel burning. Phase I included the new black liquor concentrator for the No. 2 Recovery Boiler, while Phase II includes the new black liquor concentrators for both the Nos. 2 and 3 Recovery Boilers. The No. 1 Bark Boiler and No. 1 Power Boiler will experience no changes in operation during Phase I, except for receiving additional TRS/NCG gases from the new black liquor concentrator for the No. 2 Recovery Boiler. Therefore, only the increase in emissions from the TRS and NCG gas destruction from the new black liquor concentrator were included in Phase I.

SO_2 emission increases from the No. 1 Bark Boiler and No. 1 Power Boiler were included in Phase II because the fuel burning of these units will be affected in Phase II (i.e., greater bark burning and restrictions on fuel oil burning).

The emissions from the two proposed new black liquor concentrators, which will be captured and sent to the No. 1 Bark Boiler and the No. 1 Power Boiler for control and destruction, are included in the PSD applicability analysis shown in Table 3-3. The detailed calculations for the projected actual emissions for Phase I and Phase II were included in Tables 2-2 and 2-3.

Comment 5. **In the application and as reflected in Tables 2-1, 2-2, 2-3, 3-3 and 3-4, your PSD netting analysis was based on "baseline actual emissions" to "projected actual emissions". Baseline actual emissions are defined at Rule 62-210.200 (Definitions), F.A.C., as follows: "For an existing emissions unit (other than an electric utility steam generating unit), baseline actual emissions means the average rate, in tons per year, at which the emissions unit <u>actually</u> emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 10-year period immediately preceding the date a complete permit application is received by the Department, except that the 10-year period shall not include any period earlier than November 15, 1990." It appears that your calculations used the actual sulfur content, by weight, of the fuel oil fired in 2002 (1.9%) and the consumption from the years 2004 and 2005. Based on Table A-6, the baseline years 2004 and 2005 lists the actual fuel sulfur contents, by weight, that were fired as 1.8% and 1.6%, respectively. Therefore, recalculate and submit the baseline actual emissions for SO_2 for each affected emissions unit using consistent years for the actual fuel consumption and actual fuel sulfur and make any adjustments to the affected tables and project proposal as necessary.**

Response 5: Of the tables referenced, only Tables 2-1, 3-3, and 3-4 contain the baseline actual emissions for SO_2. The baseline actual SO_2 emissions for units burning fuel oil were calculated in the Appendix A tables. The actual fuel usage from each year was used with the actual average annual sulfur content from the fuel oil used that year. For the years 1997 through 1999, the actual fuel oil sulfur content was not available, so the maximum permitted 2.5-percent sulfur content was used in those annual calculations. The actual annual average fuel oil sulfur content was used for the baseline actual calculations for the years 2000 through 2006. These fuel oil contents can be seen in Tables A-2 and A-6 for the No. 2 Recovery Boiler, Tables A-8 and A-12 for the No. 3 Recovery Boiler, Tables A-14 and A-17 for the No. 1 Power Boiler, Tables A-24 and A-28 for the No. 1 Bark Boiler, and Tables A-30 and A-34 for the No. 2 Bark Boiler. The baseline actual emissions were calculated correctly in accordance with Rule 62-210.200, F.A.C. For the year 2004, the sulfur content is 1.8 percent, and for 2005 it is 1.6 percent. The SO_2 emission factors reflect these sulfur contents.

Tables 2-2 and 2-3 contain the calculations for the projected actual emissions for Phase I and Phase II of the proposed Buckeye Energy Independence Project. A fuel oil sulfur content of 1.9 percent was used in calculating the projected actual SO_2 emissions for Phase I and Phase II in Tables 2-2 and 2-3. This represented the maximum fuel oil annual average sulfur content from 2000 through 2007, when data for the actual sulfur content was available.

Comment 6. **For the five years following the completion of construction and startup, describe in detail how you will determine SO_2 actual emissions for each affected emissions unit covered under this project to satisfy the reporting requirements of Rule 62-210.370, F.A.C. For this demonstration, address all of the allowable fuels (i.e., No. 6 fuel oil, on-specification fuel oil and tall oil) and include the following: use of any restricted fuel consumption; fuel monitoring; continuous monitoring; fuel deliveries (use of a bill-of-lading); fuel transfers (tall oil and/or on-specification used oil); fuel sampling (use of an as-fired drip sample: where, when and how); fuel-sampling analyses (in-house or out-sourced and response time for analysis); associated frequencies; and other methods to provide reasonable assurance that the project is not subject to PSD preconstruction review for SO_2 emissions.**

Response 6: The emissions of SO_2 will be determined for each individual fuel as follows:

- **Black Liquor Solids (BLS):**
  Emission Units firing fuel: No. 2 Recovery Boiler (EU 006) and No. 3 Recovery Boiler (EU 007).
  Fuel Monitoring: The amount of BLS fired in the Nos. 2 and 3 Recovery Boilers will be calculated by measuring the flow and density (percent solids) of the black liquor.
  Emissions Calculation: The SO_2 emissions will be determined by using the most current emission factor for BLS firing in NDCE recovery furnaces (currently 0.74 lb SO_2 per ton BLS from NCASI Technical Bulletin No. 884, Table 4.12, median value). This is the factor used to calculate the projected actual emissions.

- **No. 6 Fuel Oil / No. 2 Fuel Oil:**
  Emission Units firing fuel: No. 1 Power Boiler (EU 002), No. 1 Bark Boiler (EU 004), No. 2 Recovery Boiler (EU 006), No. 3 Recovery Boiler (EU 007), and No. 2 Bark Boiler (EU 019).
  Fuel Monitoring: The amount of fuel oil fired in the boilers is monitored by flow meters, and daily fuel consumption records are kept. The fuel oil sulfur content is documented in fuel receipts for every delivery to the facility.
  Emissions Calculation: The SO_2 emissions will be determined by using the annual average fuel oil sulfur content, as well as the current emission factor from AP-42, Table 1.3-1, which was used for the projected actual emissions [SO_2 = 157(S) pounds per thousand gallons]. It will be assumed that no SO_2 removal occurs in the wet scrubbers serving the bark boilers.

- **Natural Gas:**
  Emission Units firing fuel: No. 1 Power Boiler (EU 002) and No. 2 Power Boiler (EU 003).
  Fuel Monitoring: The amount of natural gas fired in the boilers is monitored by flow meters, and daily fuel consumption records are kept.
  Emissions Calculation: The SO_2 emissions will be determined by using the current emission factor from AP-42, Table 1.4-2 (0.6 pounds per million cubic feet).

- **Wood/Bark:**
  Emission Units firing fuel: No. 1 Bark Boiler (EU 004) and No. 2 Bark Boiler (EU 019).
  Fuel Monitoring: The amount of wood/bark fired in the boilers is determined by calculating the total heat input to the boilers from the steam production rates, and subtracting out the heat input due to fossil fuel combustion. The heating value for the wood is then used to determine the tons of wood fired.
  Emissions Calculation: The SO_2 emissions will be determined by using the most current emission factor for wood firing (currently 0.27 lb SO_2 per ton wood from NCASI Technical Bulletin No. 884, Table 9.6a, median value). This factor was used in determining the projected actual emissions. It is assumed that 40 percent of the SO_2 from wood/bark firing is removed in the Bark Boiler scrubbers.

- **Facility-Generated Tall Oil (blended with No. 6 fuel oil):**
  Emission Units firing fuel: No. 1 Power Boiler (EU 002), No. 1 Bark Boiler (EU 004), No. 2 Recovery Boiler (EU 006), No. 3 Recovery Boiler (EU 007), and No. 2 Bark Boiler (EU 019).
  Fuel Monitoring: The amount of tall oil blended with No. 6 fuel oil will be monitored by flow meters for continuous addition, and calculated by capacities of railcars and tank trucks during batch operations. Daily tall oil consumption records will be kept. The tall oil fuel oil sulfur content will be determined by calculating an annual average of monthly analyses of a representative sample.
  Emissions Calculation: The SO_2 emissions will be determined by a stoichiometric calculation using the sulfur content of the tall oil used, the tall oil burned, and the tall oil density. It will be assumed that no SO_2 removal occurs in the wet scrubbers serving the bark boilers.

- **Used Oil:**
  Emission Units firing fuel: No. 1 Power Boiler (EU 002), No. 1 Bark Boiler (EU 004), No. 2 Recovery Boiler (EU 006), No. 3 Recovery Boiler (EU 007), and No. 2 Bark Boiler (EU 019).
  Fuel Monitoring: The amount of purchased lubricating oil will be recorded, and will be assumed to all become used oil and combusted with No. 6 fuel oil.
  Emissions Calculation: The SO_2 emissions will be determined in the same way as with No. 6 fuel oil combustion. The sulfur content of the used oil will be conservatively assumed to be the same as that of the No. 6 fuel oil. It will be assumed that no SO_2 removal occurs in the wet scrubbers serving the bark boilers.

Comment 7. Are all of the affected emissions units receiving their fuel from a day tank(s) or directly from a bulk storage tank(s)?

Response 7: Buckeye utilizes an oil system that is common for all the boilers that can burn No. 6 oil [No. 1 Power Boiler (EU 002), No. 1 Bark Boiler (EU 004), No. 2 Recovery Boiler (EU 006), No. 3 Recovery Boiler (EU 007), No. 4 Recovery Boiler (EU 011), and No. 2 Bark Boiler (EU 019)]. There is a bulk storage tank (100,000 gallon capacity) on site where oil is stored as it is received from either truck or rail. When tall oil is being burned, it is mixed with No. 6 fuel oil in this bulk tank.

The tall oil is supplied to the No. 6 fuel oil bulk storage tank from tall oil storage tanks via tank truck, railcar, or direct piping.

The pumps on the No. 6 fuel oil storage tank circulate oil into the Powerhouse for additional heating and to supply the fossil fuel burners on the boilers that burn No. 6 fuel oil. After the heaters, the oil flows to each boiler where No. 6 oil is burned, as well as the No. 4 Lime Kiln (EU 024) fuel oil day tank. Oil is re-circulated through the burner supply piping at each boiler and is returned back to the No. 6 fuel oil storage tank. This system is designed to insure oil temperature is maintained at the appropriate temperature in the storage tank as well for firing at each boiler. There will be no changes to the No. 6 fuel oil storage or supply system as a result of the Foley Energy Independence Project.

The bark boilers can be fired on No. 6 fuel oil using their auxiliary fuel burners, but usually these burners are used for start-up, to supplement steam generation if other boilers are out-of-service, or during upset conditions. Generally fossil fuel usage on the bark boilers is kept to an absolute minimum, as steam generated from oil is much more expensive than steam generated from bark (biomass). The bark boilers generate steam predominantly from bark.

Bark is produced as a waste stream from the de-barking process of the logs received for the pulp process. Bark is also purchased as needed to have adequate quantities to fire the bark boilers. Wet bark is stored on the ground in a pile to be reclaimed for use in the boilers. The reclaimed bark first supplies a rotary dryer, where a portion of the flue gas from the No. 2 Bark Boiler is used to dry the bark. Bark is dried from a moisture content of approximately 50 percent to approximately 30-percent moisture content. After drying, the bark is conveyed to live bottom bins. There is one bin for each of the bark boilers. Bark is fed from the live bottom bins to fire each boiler. Currently the firing rates of the bark boilers vary inversely with the firing rate of the power boilers in order to maintain and control steam header pressure.

After the condensing turbine generator is installed, steam header pressure will be controlled by modulating the steam flow to the condensing turbine instead of varying the firing rate of the power and bark boilers. Therefore the bark boilers will be base loaded, which will allow them to operate at a higher average rate than if they have to vary to control header pressure as they currently do. There will not be an increase in the peak firing capability of the bark boilers as a result of the project. It is expected that the average steam generated from the bark boilers will increase.

As the steam generated from less expensive or free bio-mass fuels (bark and/or black liquor) increases due to the project changes, steam generated from fossil fuel usage in the power boilers will be decreased or at times eliminated. The project will not change the design or capability of the power boilers. The only change is the installation of the condensing turbine generator, which allows the steam header pressure control strategy to change.

Fifty-percent black liquor currently is supplied to a black liquor oxidation system for oxidation. Oxidation is required for liquor being fired in the direct contact evaporation recovery boilers (Nos. 2 and 3 Recovery Boilers) to allow operation with acceptable total reduced sulfur emissions. Currently, black liquor flows from the black liquor oxidation system to the cyclone evaporators on the No. 2 Recovery Boiler and to the precipitator mix tank on the No. 3 Recovery Boiler.

Black liquor recirculation pumps on the No. 2 Recovery Boiler cyclone evaporators recirculate liquor for evaporation, supply the precipitator mix tank, and supply the boiler salt cake mix tank. Liquor in the precipitator mix tank mixes with ash collected in the precipitator with the black liquor and flows by gravity back to the cyclone evaporators. Black liquor from the salt cake mix tank circulates to mix with ash collected in the generating section of the boiler and also supplies the black liquor burner pumps on the boiler. When the Foley Energy Independence Project is implemented, concentrated black liquor from liquor storage tanks will be fed directly to the salt cake mix tank. The circulation system and burner pumps on the salt cake mix tank will not be changed and the system will have the same operating capacity as the current system.

Oxidized black liquor, as stated above, is currently supplied to the precipitator mix tank on the No. 3 Recovery Boiler. Liquor in the precipitator mix tank mixes ash collected in the precipitator with the black liquor and is pumped to a sluice hopper under the generating section of the boiler. Ash collected in the generating section of the boiler mixes with the liquor and flows by gravity to the cascade evaporator. Concentrated black liquor from the cascade evaporator then flows to a salt cake mix tank which supplies the black liquor burner pumps for the boiler.

When the Foley Energy Independence Project is implemented, concentrated black liquor will be fed directly from liquor storage tanks to the salt cake mix tank. The burner pumps on the salt cake mix tank will not be changed and the system will have the same capability and the same operating function as current.

Currently the No. 2 Recovery Boiler and No. 3 Recovery Boiler, as described above, are being supplied with 50-percent oxidized black liquor. Concentrating the black liquor to the firing concentration (approximately 70 percent solids) is currently coupled to boiler operation, i.e. liquor can only be concentrated with the boiler in operation and concentrated liquor is only needed with the boiler in operation.

When the Foley Energy Independence Project is implemented, the concentration of black liquor to the firing concentration will no longer be coupled to recovery boiler operation. Black liquor concentration will occur in the concentrators, which will be coupled with evaporator operation. Therefore, concentrated black liquor storage is required to be able to operate the boilers when concentrator/evaporators systems are down for maintenance.

The No. 4 Recovery Boiler currently is a non-direct contact design boiler where concentration of the firing liquor is accomplished in a concentrator/evaporator system (No. 4 concentrator/black liquor evaporator). There currently is a concentrated black liquor storage tank used to store 65-70 percent black liquor from the No. 4 Concentrator and supply the No. 4 Recovery Boiler. When the Nos. 2 and 3 Recovery Boilers are converted to non-direct contact operation, they will also need to be supplied from a concentrated black liquor storage tank. The existing tank is not adequately sized to support operation of all three recovery boilers if a concentrator/evaporator system is down for maintenance. Therefore an additional concentrated black liquor storage tank will be installed. The new tank and existing tank will be designed such that the pumps and piping will allow any or all of the recovery boilers to be supplied from either tank, and concentrated black liquor can be transferred between tanks.

Comment 8. How much steam is needed to drive the new steam generator and at what pressure and temperature?

Response 8: The required steam to drive the new steam generator is 153,000 lb/hr. The required pressure and temperature are 600 psi and 700 degrees Fahrenheit.

Comment 9. Your response to question No. 22 in the January 10th RAI was inadequate. As previously requested, please provide the following reference documents, or at least the excerpts from the documents that were used and referenced:

- **NCASI Technical Bulletin No. 94**
- **NCASI Technical Bulletin No. 416**

- **NCASI Technical Bulletin No. 701**
- **NCASI Special Report #93-03**
- **NCASI Environmental Resource Handbook – Chemical Recovery Process (Tables A-1 & A-7)**
- **NCASI Environmental Resources Handbook 3-02 (Tables A-23 & A-29)**

If Technical Bulletin No. 650 has been updated since June 1993, please provide.

Response 9: Emission factors from these documents were not used in calculating the baseline actual emissions in the application. These emission factors were referenced in the facility Annual Operating Reports (AORs), which have been submitted to FDEP each year. These emission factors were only referenced, in order to show the difference between the original AOR factors and the factors used in the revised emission factor tables. The baseline emissions were based on the revised emission factors. Nevertheless, the excerpts from these documents have been included as Attachment D of this response.

It is noted that the emission factors in the NCASI Environmental Resource Handbook may be different than the factors used in Tables A-1, A-7, A-13, A-18, A-23, A-29, and A-35, as this document may have been revised over the years with more recent and more accurate data. The revised emission factors in Tables A-2, A-8, A-14, A-24, A-30, and A-36 are the most up to date emission factors available, and the reference materials for these factors have been provided in previous submissions to FDEP.

Thank you for your consideration of this information. If you have any questions, please do not hesitate to call me at (352) 336-5600.

Sincerely,

GOLDER ASSOCIATES INC.

David A. Buff

David A. Buff, P.E., Q.E.P.
Principal Engineer

DB/sl

Enclosures

cc: D. Weeden – Buckeye

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FACILITY INFORMATION

Professional Engineer Certification

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

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

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

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

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

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

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

   David A. Buff
   Signature

   5/21/08
   Date

   (seal)

PROFESSIONAL ENGINEER STATE OF FLORIDA DAVID A. BUFF

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

ATTACHMENT A

PROCESS FLOW DIAGRAMS

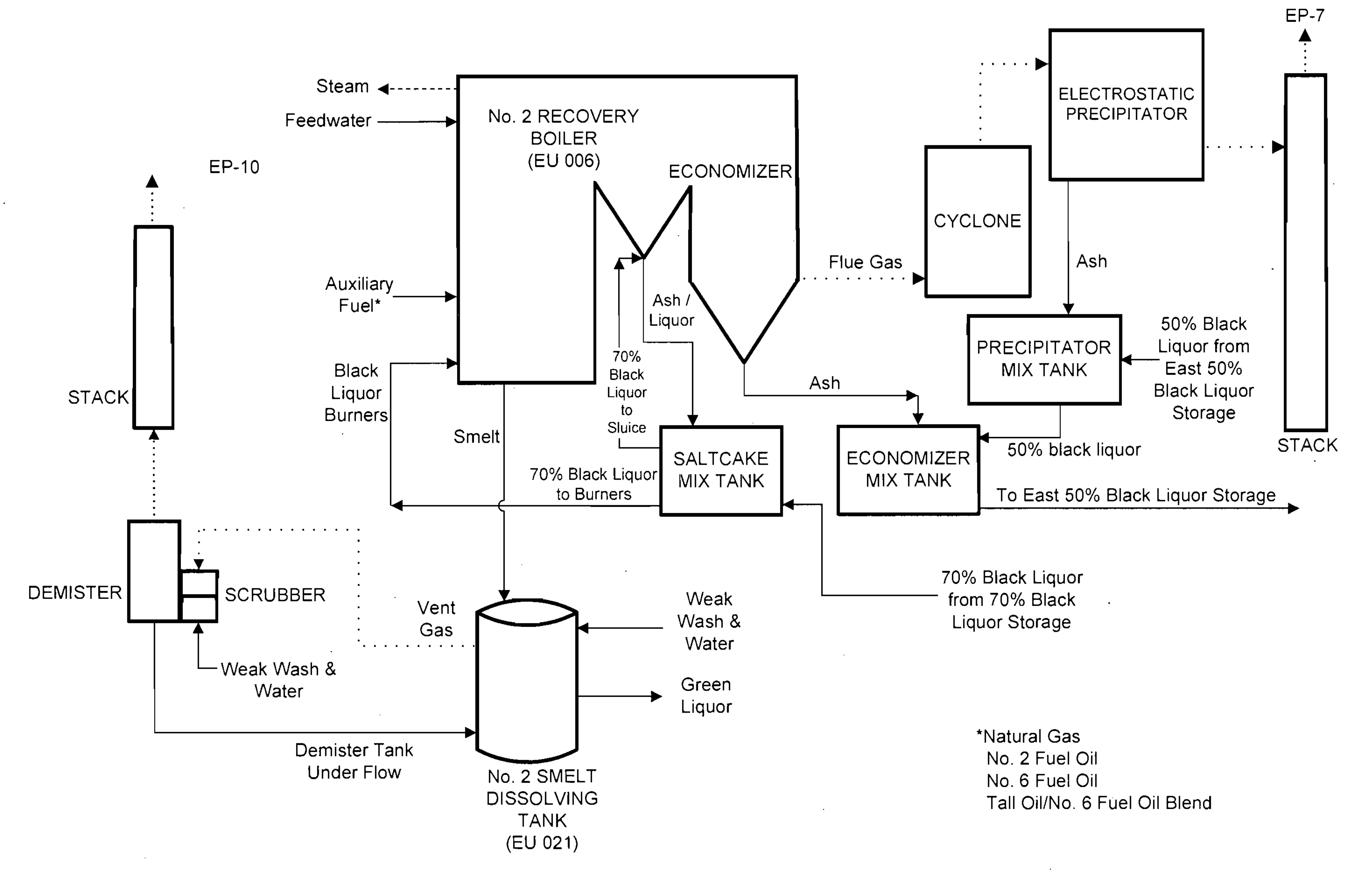

Figure 2-9
No. 2 Recovery Boiler: After Low Odor Conversion Flow Diagram
Buckeye Florida, L.P.

EIP\FIG 2-9.VSD

Process Flow Legend
Solid/Liquid
Gas
Steam

Golder Associates

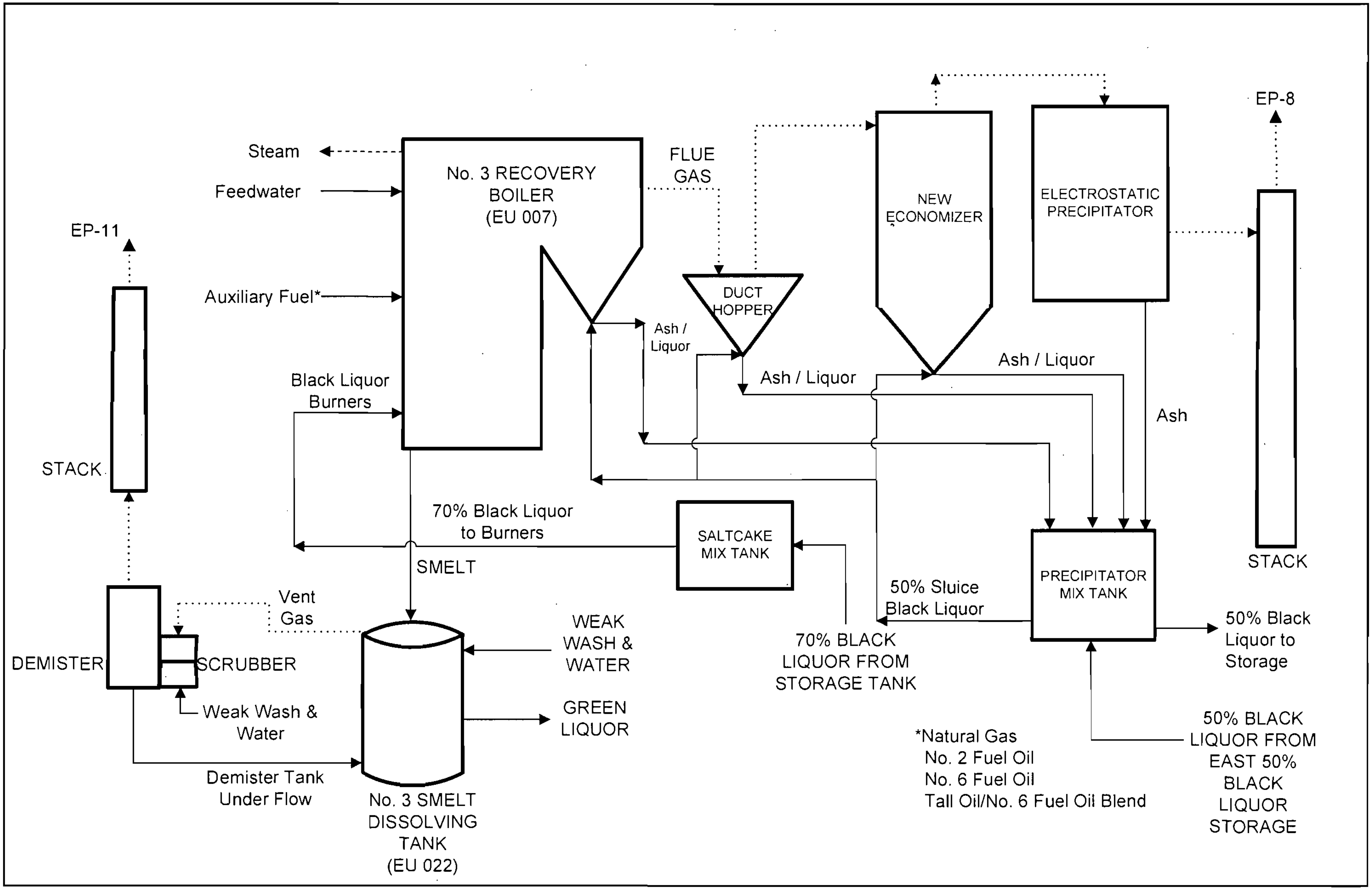

Figure 2-10
No. 3 Recovery Boiler: After Low Odor Conversion Flow Diagram
Buckeye Florida, L.P.

EIP\FIG 2-10.VSD

Process Flow Legend
Solid/Liquid ⟶
Gas · · · · · · ▸
Steam - - - - - - ▸

Golder Associates

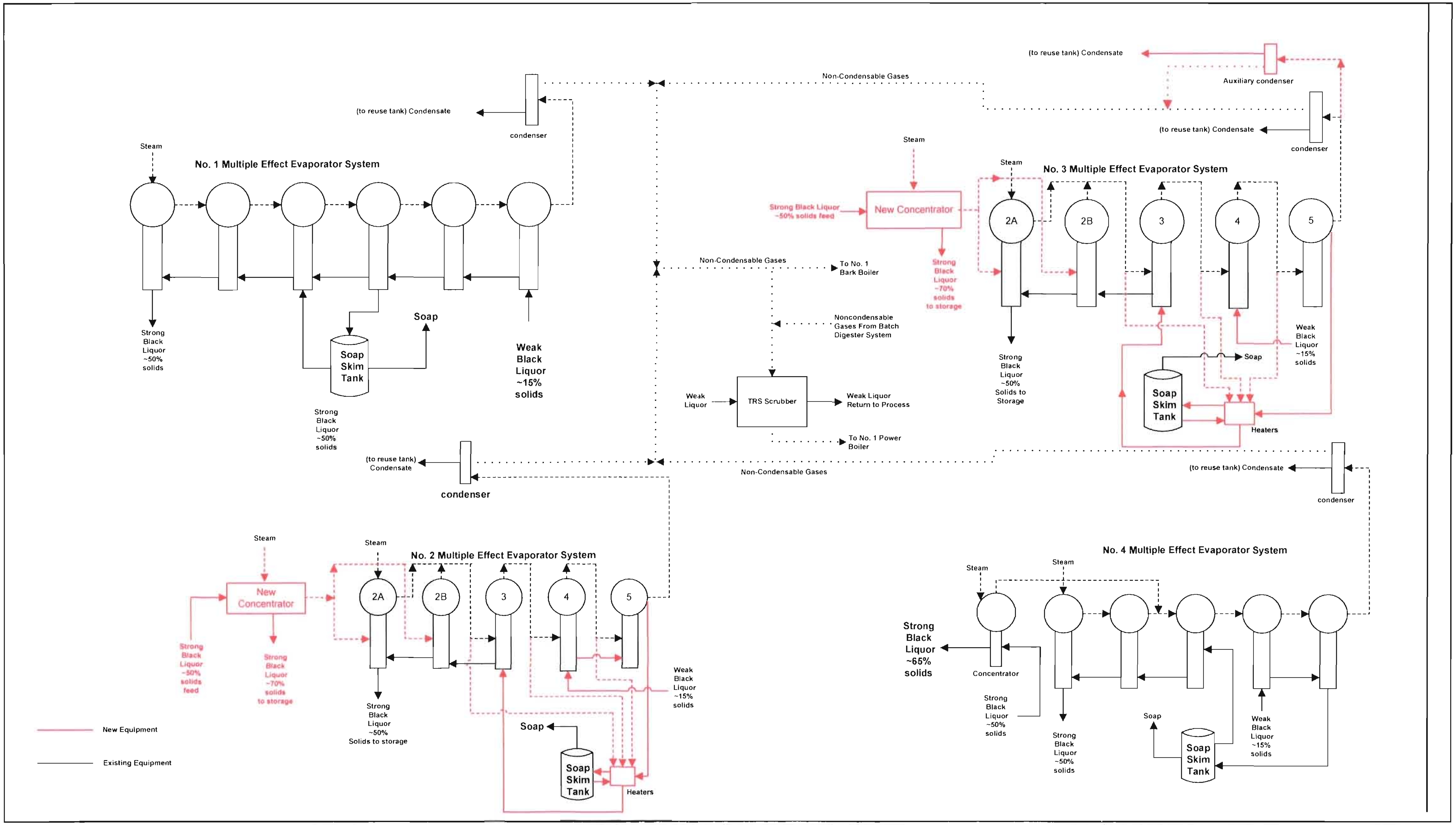

Figure 2-11
Multiple Effect Evaporator System: Proposed Process Flow Diagram
Buckeye Florida, L.P.
EIP/Fig 2-11.vsd

Process Flow Legend
Solid/Liquid
Gas
Steam/Vapor

REV.	SCALE:	
DESIGN	DB	DB
CADD	SL	SL
CHECK		
REVIEW		

Golder Associates

ATTACHMENT B

AIR CONSTRUCTION PERMITS FOR CONTEMPORANEOUS PROJECTS

Department of Environmental Protection

Jeb Bush
Governor

Northeast District
7825 Baymeadows Way, Suite B200
Jacksonville, Florida 32256-7590

David B. Struhs
Secretary

October 9, 2001

NOTICE OF PERMIT

CERTIFIED-RETURN RECEIPT

Mr. Howard Drew, V. P., Wood Cellulose Manufacturing
Buckeye Florida, Limited Partnership
One Buckeye Drive
Perry, Florida 32348-7702

Dear Mr. Drew:

Taylor County - AP
Buckeye Florida, Limited Partnership
MACT I Compliance:
No. 1 Bark Boiler,
No. 1 Power Boiler
No. 2 Purification Plant
Pulping System – MACT I

Enclosed is Permit Numbers 1230001-011-AC and 1230001-012-AC to construct the subject air pollution emissions unit(s), issued pursuant to Section 403.087, Florida Statutes (FS).

Any party to this order has the right to seek judicial review of it under section 120.68 of the Florida Statutes, by filing a notice of appeal under rule 9.110 of the Florida rules of Appellate Procedure with the clerk of the Department of Environmental Protection in the Office of General Counsel, Mail Station 35, 3900 Commonwealth boulevard, Tallahassee, Florida, 32399-3000, and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate district court of appeal. The notice must be filed within thirty days after this order is filed with the clerk of the Department.

Executed in Jacksonville, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

OCT 12 2001

Christopher L. Kirts, P. E.
District Air Program Administrator

CLK:RFS

FILING AND ACKNOWLEDGEMENT
FILED, on this date pursuant to S120.52 Florida **Statutes,** with the designated Department Clerk, receipt of which is hereby acknowledged.
Dorothy Bonefield 10/11/01
Clerk

cc: Carla Ferguson, Buckeye Florida, Limited Partnership
David A. Buff, P.E., Golder Associates, Inc.

Department of Environmental Protection

Northeast District
7825 Baymeadows Way, Suite B200
Jacksonville, Florida 32256-7590

Jeb Bush
Governor

David B. Struhs
Secretary

PERMITTEE:

Buckeye Florida, Limited Partnership
One Buckeye Drive
Perry, Florida 32347

I.D. Number:	1230001
Permit/Cert Number:	1230001-011-AC 1230001-012-AC
Date of Issue:	October 9, 2001
Expiration Date:	October 9, 2003
County:	Taylor
Latitude/Longitude:	30° 03' 59" N; 83° 33' 12" W
UTM:	E-(17) 256.7; N-3328.7
Project:	MACT 1 Compliance: No. 1 Bark Boiler, No. 1 Power Boiler No. 2 Purification Plant Pulping System – MACT I

This permit is issued under the provisions of Chapter(s) 403, Florida Statutes, and Florida Administrative Code Rule(s) 62-210, 62-212, 62-296, 62-297 and 62-4. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawing(s), plans, and other documents attached hereto or on file with the department and made a part hereof and specifically described as follows:

For the installation and implementation of equipment necessary for compliance with the kraft pulping and bleaching systems standards of 40 CFR Part 63, Subpart S (MACTI), the emission units are identified below:

Emission Unit 002: No. 1 Power Boiler

Emission Unit 004: No. 1 Bark Boiler

Emission Unit 041: No. 2 Purification Plant

Emission Unit 046: Pulping System MACT I

The Pulping System – MACT I includes those sources regulated under MACT I: Nos. 1 and 2 Batch Digester systems, the Turpentine Recovery system (includes the turpentine Condenser, Decanter, Weir Box, and Underflow Tank), Multiple Effect Evaporator systems (Nos. 1-4), and the Pulping Process Condensate Collection System.

Project Description:

Buckeye Florida, Limited Partnership - Foley Mill, was granted a Pollution Control Project (PCP) Exclusion for this project pursuant to the requirements of Rule 62-212.400(2)(a)2.b, F.A.C.

Noncondensible gases (NCGs) from the existing turpentine decanter, the turpentine underflow tank, and the digester accumulator lines will be collected and tied into the existing Low Volume High Concentration (LVHC) gas collection system, then routed for combustion to the No. 1 Bark Boiler (primary device) or the No. 1 Power Boiler (secondary/backup device for MACT). [1]

PERMITTEE:

Buckeye Florida, Limited Partnership
One Buckeye Drive,
Perry, Florida 32347

I.D. Number: 1230001
Permit/Cert Number: 1230001-011-AC
Date of Issue: October 9, 2001
Expiration Date: October 9, 2003
County: Taylor

The estimated increase in TRS and SO2 emissions as a result of the combustion of the NCGs from these sources in the No. 1 Bark Boiler are 9.3 E –04 TPY and 0.3 TPY, respectively.

This project is part of the MACT compliance plan for the Foley plant and will result in a net emissions decrease of 49.9 TPY of TRS and 5.7 TPY of HAPs. For the No. 1 Power Boiler, the estimated increase in SO2, TRS, HAPs, and SAM emissions as a result of NCG burning in the No. 1 Power Boiler (while burning natural gas) from all MACT required sources, is 124.1 TPY, 0.13 TPY, 0.16TPY and 7.6 TPY, respectively.[1] Buckeye has elected to either (1) burn only natural gas or (2) burn limited amounts of fuel oil with pre-scrubbing from the existing backup scrubber while LVHC NCGs are burned in the No. 1 Power Boiler. As a result, this project will not result in an increase in the allowable emissions for SO2 at this emissions unit. The No. 1 Power Boiler will be used as the backup control device to the No. 1 Bark Boiler for a period of time not to exceed 20 days out of a calendar year (i.e. 480 hr/yr).

The equipment at each bleaching stage of the No. 2 Purification Plant, where chlorinated compounds are introduced, will be enclosed and vented into a closed-vent system and routed to the wet scrubber. A continuous monitoring system (CMS) will be installed to measure parameters established by the 40 CFR Part 63, Subpart S regulation.

[1] Summary of the net emissions changes based on LVHC NCG Combustion in the No. 1 Power Boiler (as a secondary control device):

		Pollutants Emission Rate (TPY)							
		SO2	NOx	CO	PM/PM10	TRS	VOC	SAM	HAPs
Total Proposed Modifications	No. 1 Power Boiler as backup/secondary device and firing natural gas (MODE 1)*	124.1	---	---	---	0.13	---	7.6	0.16
	No. 1 Power Boiler as backup/secondary device and firing fuel oil w/ existing TRS scrubber (at No. 1 Bark Boiler) as preliminary control device (MODE 2)*	62.1**	---	---	---	0.07**	---	3.8**	0.16
Existing Emissions	No. 1 Power Boiler as backup/secondary device for LVHC NCG gases	0	---	---	---	0	---	0	0
	Backup TRS+ Scrubber for LVHC NCG gases at the No. 1 Bark Boiler	---	---	---	---	50	---	0	5.9
Total of Existing Emissions		0	---	---	---	50	---	0	5.9
TOTAL NET CHANGE		124.1++	---	---	---	-49.9	---	7.6++	-5.7

* The No. 1 Power Boiler is the backup combustion device to comply with MACT I requirements for control of LVHC gases. It will be operated in either of two modes. Mode 1: The No. 1 Power Boiler is the backup TRS combustion device while burning natural gas and LVHC. Mode 2: LVHC NCG gases will be routed to the existing TRS scrubber (previously used at the No. 1 Bark Boiler) as a preliminary TRS control, followed by combustion in the No. 1 Power Boiler during time periods only when fuel oil and LVHC gases are burned in this boiler.

** May be less if TRS Removal in existing TRS scrubber is greater than the estimated 50%.

\+ For existing emissions at the No. 1 Bark Boiler, the TRS Scrubber is the TRS Control backup control device

\++ Above Significant Threshold. A Pollution Control Project (PCP) Exclusion was granted pursuant to 62-212.400(2)(a)2.b.

PERMITTEE:

Buckeye Florida, Limited Partnership
One Buckeye Drive,
Perry, Florida 32347

I.D. Number:	1230001
Permit/Cert Number:	1230001-011-AC
Date of Issue:	October 9, 2001
Expiration Date:	October 9, 2003
County:	Taylor

Project Description Continued:

Located: Route 17, Perry, Taylor County, Florida.

In accordance with:

Construction permit application for the No. 1 Bark Boiler received April 14, 1999
Additional Information Received June 9, 1999
Intent to Issue and Draft permit dated August 20, 1999
Comments from Buckeye Received September 16, 1999
Comments from Applicant received March 23, 2001
Comments from Applicant received April 18, 2001
Comments from Applicant received April 19, 2001
Comments from Applicant received August 24, 2001
Comments from Applicant received September 13, 2001

Construction permit application for the No. 1 Power Boiler received July 10, 2000
Additional Information Received November 13, 2000
Additional Information Received February 12, 2001
Comments from Applicant received April 18, 2001
Comments from Applicant received April 19, 2001
Additional Information Received June 4, 2001
Comments from Applicant received June 20, 2001
Comments from Applicant received August 24, 2001
Comments from Applicant received September 13, 2001

PERMITTEE:

Buckeye Florida, Limited Partnership	I.D. Number:	1230001
One Buckeye Drive,	Permit/Cert Number:	1230001-011-AC
Perry, Florida 32347	Date of Issue:	October 9, 2001
	Expiration Date:	October 9, 2003
	County:	Taylor

GENERAL CONDITIONS:

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

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

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

4. This permit conveys not title to land or water, does not constitute State recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title.

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

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

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

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

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

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

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

PERMITTEE:

Buckeye Florida, Limited Partnership		I.D. Number:	1230001
One Buckeye Drive,		Permit/Cert Number:	1230001-011-AC
Perry, Florida 32347		Date of Issue:	October 9, 2001
		Expiration Date:	October 9, 2003
		County:	Taylor

GENERAL CONDITIONS:

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

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

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

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

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

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

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

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

13. This permit also constitutes:

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

PERMITTEE:

		I.D. Number:	1230001
Buckeye Florida, Limited Partnership		Permit/Cert Number:	1230001-011-AC
One Buckeye Drive,		Date of Issue:	October 9, 2001
Perry, Florida 32347		Expiration Date:	October 9, 2003
		County:	Taylor

GENERAL CONDITIONS:

14.. The permittee shall comply with the following:

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

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

c. Records of monitoring information shall include:

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

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

PERMITTEE:

Buckeye Florida, Limited Partnership
One Buckeye Drive,
Perry, Florida 32347

I.D. Number:	1230001
Permit/Cert Number:	1230001-011-AC
Date of Issue:	October 9, 2001
Expiration Date:	October 9, 2003
County:	Taylor

SPECIFIC CONDITIONS:

1. Total HAP emissions from the following equipment systems shall be controlled as specified in Specific Condition No. 2:

   - Batch digesters
   - The turpentine recovery system (condensers, decanters)
   - The multiple effect evaporators
   - Any other equipment serving the same function as those previously listed

   [40 CFR 63.443(a)]

   Note: Non-decanting turpentine storage tanks containing saleable product are not considered part of the turpentine recovery process. [EPA MACT I Rule Interpretation: Q&A's For The Pulp and Paper NESHAP, EPA Document, 9/22/99, Florida DEP Memorandum: Summary of Responses to MACT I Issues... dated August 29, 2000]

2. Each equipment system listed in Specific Condition No. 1 shall be enclosed and vented into a closed-vent system and routed to the No. 1 Bark Boiler or the No. 1 Power Boiler for control of total HAP emissions. The enclosures and closed-vent system shall meet the requirements specified in Specific Condition No. 14. The HAP emission stream shall be introduced with the primary fuel or into the flame zone; or controlled in a boiler with a heat input capacity greater than or equal to 150 million British thermal Units per hour by introducing the HAP emission stream with the combustion air.
   [40 CFR 63.443(c), 40 CFR 63.443(d)(4)(i) and (ii)].

3. Periods of excess emissions reported under Specific Condition No. 13 shall not be a violation of Specific Condition No. 2 provided that the time of excess emissions (excluding periods of startup, shutdown, or malfunction) divided by the total process operating time in a semi-annual reporting period does not exceed 4% for the No. 1 Bark Boiler and the No. 1 Power Boiler. [40 CFR 63.443(e)]

   Excess emissions due to startup, shutdown or malfunction are allowed for up to eight (8) hours in any 24 hour period unless otherwise requested and approved, provided effort is made to minimize emissions and duration in accordance with Rule 62-210.700 F.A.C.

The following conditions apply to Emission Units 002, The No. 1 Power Boiler:

Total Reduced Sulfur (TRS) Requirements (when NCGs are routed to the No. 1 Power Boiler for combustion and the TRS backup scrubber is not in operation):

4a. Emission Limits and Standards. When NCG gases are collected and routed to this Emissions Unit, and the unit is firing natural gas, TRS emissions shall not exceed 5 ppmvd @ 10% O2, as a 12 hour average; 2.28 lbs/hr and 0.55 TPY. TRS Emissions shall be incinerated for a minimum of 0.5 second and at a minimum of 1200°F. [Rule 62-296.404(3)(f)1., F.A.C.]

4.b. TRS Emissions. It is assumed that compliance with the TRS emissions limit stated in Specific Condition 4.a. is achieved by maintaining the minimum temperature of 1200°F and the 0.5 second residence time. [Rule 62-404(3)(a)1., 40 CFR 60.283(a)(1)(iii)]

appl ble ?

PERMITTEE:

Buckeye Florida, Limited Partnership
One Buckeye Drive,
Perry, Florida 32347

I.D. Number: 1230001
Permit/Cert Number: 1230001-011-AC
Date of Issue: October 9, 2001
Expiration Date: October 9, 2003
County: Taylor

SPECIFIC CONDITIONS:

5. The HAP emission stream shall be routed to the No. 1 Power Boiler for destruction for a period not to exceed 20 calendar days per year, i.e. 480 hours per year unless otherwise approved by the Department.

The following conditions apply to Emission Unit 041, No. 2 Purification Plant:

6. Capacity. The maximum allowed operation rate is listed below:

RATE	MATERIAL
1681 TPD[1]	Bone-dry Unbleached Pulp Feed

[1] Based on a nominal operation rate of 700 TPD for the No. 1 Purification Plant and 981 TPD for the No. 2 Purification Plant. (Ton =2000 pounds).

{Permitting note: The capacity limitations have been placed in this permit to identify the capacity of each emissions unit for purposes of confirming that emissions testing is conducted within 90-100 percent of the emissions unit's rated capacity (or to limit future operation to 110 percent of the test load), to establish appropriate limits and to aid in determining future rule applicability.}

[Construction permit Number 1230001-013-AC; Final Title V Permit Number 123001-007-AV]

7. The equipment at each bleaching stage of the No. 2 Purification Plant, where chlorinated compounds are introduced, shall be enclosed and vented into a closed-vent system and routed to the gas scrubber that meets the requirements specified in Specific Condition No. 8. The enclosures and closed-vent system shall meet the requirements specified in Specific Condition No. 14. If process modifications are used to achieve compliance with the emissions limit specified in Specific Condition No. 8, enclosures and closed-vent systems are not required, unless appropriate. [40 CFR 63.445(b)]

8. The gas scrubber listed in Specific Condition No. 7 shall achieve a treatment device outlet concentration of 10 parts per million or less by volume of total chlorinated HAP measured as chlorine. [40 CFR 63.445(c)(2)].

9. The permittee shall comply with the MACT requirements for chloroform emissions at this emissions unit by eliminating the use of chlorine and sodium hypochlorite used for bleaching in the No. 2 purification plant. [40 CFR 63.445(d)(2)].

The following conditions are common to Emission Units Nos. 002, 004, 041, and 046:

10. The ID Number and Project Name for this source shall be used on all correspondences.

PERMITTEE:

Buckeye Florida, Limited Partnership		I.D. Number:	1230001
One Buckeye Drive,		Permit/Cert Number:	1230001-011-AC
Perry, Florida 32347		Date of Issue:	October 9, 2001
		Expiration Date:	October 9, 2003
		County:	Taylor

SPECIFIC CONDITIONS:

11. The following specific conditions of the below referenced permits shall be superceded with the issuance of this permit:

Emission Unit	Permit Number	Specific Condition Number(s)
No. 2 Purification Plant	1230001-013-AC	13
	1230001-005-AV	N.4., N.5., N.6.

12. The permittee shall comply with the applicable requirements of 40 CFR Part 63, Subpart S no later than April 17, 2002 as extended pursuant to 40 CFR Part 63, Subpart A [1]. [40 CFR 63.440(d)].

[1] Letter from Christopher Kirts, FDEP to John Crowe, Buckeye dated January 4, 2000.

13. The permittee shall comply with the requirements of 40 CFR Part 63, Subpart A- General Provisions as indicated in Table 1 of Subpart S.
[40 CFR 63.440(g)].

Standards for enclosures and closed-vent systems:

14. Each enclosure and closed-vent system specified in Specific Conditions Nos. 2 and 7 for capturing and transporting vent streams that contain HAP shall meet the following requirements.

(a) Each enclosure shall maintain negative pressure at each enclosure or hood opening as demonstrated by the procedures specified in Specific Condition No. 25. Each enclosure or hood opening closed during the initial performance test specified in Specific Condition No. 22 shall be maintained in the same closed and sealed position as during the performance test at all times except when necessary to use the opening for sampling, inspection, maintenance, or repairs.

(b) Each component of the closed-vent system used to comply with Specific Conditions Nos. 2 and 7 that is operated at positive pressure and located prior to a control device shall be designed for and operated with no detectable leaks as indicated by an instrument reading of less than 500 parts per million by volume above background, as measured by the procedures specified in Specific Condition No. 24.

(c) Each bypass line in the closed-vent system that could divert vent streams containing HAP to the atmosphere without meeting the emission limitations in §§63.443 and §§63.445 shall comply with one of the following requirements:

(1) On each bypass line, the permittee shall install, calibrate, maintain, and operate according to manufacturer's specifications a flow indicator that provides a record of the presence of gas stream flow in the bypass line at least once every 15 minutes. The continuous monitor will measure the valve position of the vent valve as a flow indicator. All valve positions other than closed will indicate flow in the bypass line; and

(2) For bypass line valves that are not computer controlled, the permittee shall maintain the bypass line valve in the closed position with a chained and locked closure mechanism in such a way that the valve or closure mechanism cannot be opened without recording and reporting the valve opening.

Note: Buckeye plans on demonstrating compliance with Specific Condition No.14(c)(1) by monitoring computer (DCS) controlled automatic valves with a continuous indication of any venting and the capability to record venting periods at least once every 15 minutes on each bypass line. The bypass lines are (2) two ten-inch vent collection lines located in the pulping and power operating departments.
[40 CFR 63.450]

PERMITTEE:

Buckeye Florida, Limited Partnership
One Buckeye Drive,
Perry, Florida 32347

I.D. Number:	1230001
Permit/Cert Number:	1230001-011-AC
Date of Issue:	October 9, 2001
Expiration Date:	October 9, 2003
County:	Taylor

SPECIFIC CONDITIONS:

Monitoring Requirements

15. The permittee shall install, calibrate, certify, operate, and maintain according to the manufacturer's specifications, a continuous monitoring system (CMS) as specified in Specific Condition No. 16.a. The CMS shall include a continuous recorder. [40 CFR 63.453(a)].

16.a. A CMS shall be operated to measure the following parameters for the gas scrubber used to comply with the bleaching system requirement in Specific Condition No. 8:

(1) The pH or the oxidation/reduction potential of the gas scrubber effluent;
(2) The gas scrubber liquid influent flow rate; and
(3) The on/off operation of the scrubber fan. [1]

[40 CFR 63.453(c)]

[1] An alternative to monitoring the gas inlet flow rate. Buckeye also proposes to 1) provide the manufacturer scrubber fan curve date in the performance test plan and in the CMS Quality Control Program; 2) conduct outlet gas scrubber flow measurement during the initial performance test and test at maximum gas flow conditions; 3) notify FDEP-NED prior to making any changes that will affect the maximum gas flow rate (i.e., motor replacement, fan replacement); and 4) conduct performance testing after making any future changes which could increase the maximum inlet flow rate.

[EPA MACT I Rule Interpretation: Q&A's For The Pulp and Paper NESHAP, EPA Document, 9/22/99, Florida DEP Memorandum: Summary of Responses to MACT I Issues... dated August 29, 2000, Buckeye Letter dated 4/17/01]

16.b. The permittee may request to use an alternative monitoring method for those stated in Specific Condition No.16.a, by submitting an application to the Administrator (USEPA) as described in 40 CFR 62.8(f)(4)(ii). However, until the Administrator (USEPA) has granted such approval, the permittee remains subject to the requirements of Specific Condition No.16.a.
[40 CFR 63.8(f)]

17. Each enclosure and closed-vent system used to comply with Specific Condition No.14 shall comply with the following requirements:

(1) For each enclosure opening, a visual inspection of the closure mechanism specified in Specific Condition No. 14 (a) shall be performed at least once every 30 days to ensure the opening is maintained in the closed position and sealed.

(2) Each closed-vent system shall be visually inspected at least once every 30 days and at other times as requested by the Administrator. The visual inspection shall include inspection of ductwork, piping, enclosures, and connections to covers for visible evidence of defects.

(3) For positive pressure closed-vent systems or portions of closed-vent systems, demonstrate no detectable leaks as specified in Specific Condition No.14.(b) measured initially and annually by the procedures in Specific Condition No. 24.

(4) Demonstrate initially and annually that each enclosure opening is maintained at negative pressure as specified in Specific Condition No. 25.

(5) The valve or closure mechanism specified in Specific Condition No. 14.(c)(2) shall be inspected at least once every 30 days to ensure that the valve is maintained in the closed position and the emission point gas stream is not diverted through the bypass line.

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Perry, Florida 32347		Date of Issue:	October 9, 2001
		Expiration Date:	October 9, 2003
		County:	Taylor

SPECIFIC CONDITIONS:
Specific Condition Number 17 Continued:

(6) If an inspection required by Specific Conditions Nos. 17.(1) through 17.(5) identifies visible defects in ductwork, piping, enclosures or connections to covers required in Specific Condition No.14, or if an instrument reading of 500 parts per million by volume or greater above background is measured, or if enclosure openings are not maintained at negative pressure, then the following corrective actions shall be taken as soon as practicable.
   (i) A first effort to repair or correct the closed-vent system shall be made as soon as practicable but no later than 5 calendar days after the problem is identified.
   (ii) The repair or corrective action shall be completed no later than 15 calendar days after the problem is identified. Delay of repair or corrective action is allowed if the repair or corrective action is technically infeasible without a process unit shutdown or if the owner or operator determines that the emissions resulting from immediate repair would be greater than the emissions likely to result from delay of repair. Repair of such equipment shall be completed by the end of the next process unit shutdown.
[40 CFR 63.453(k)]

18. For each control device, technique or an alternative parameter other than those specified in Specific Condition Nos. 2, 16.a., and 17, the permittee shall install a CMS and establish appropriate operating parameters to be monitored that demonstrate, to the EPA Administrator's satisfaction, continuous compliance with the applicable control requirements.
[40 CFR 63.453(m)]

19. The permittee shall use the following procedures to establish or reestablish the value for each operating parameter required to be monitored under Specific Condition Nos. 16.a., and 18 or to establish appropriate parameters for Specific Condition No. 18.
   (1) During the initial performance test required in Specific Condition No. 22 or any subsequent performance test, continuously record the operating parameter;
   (2) Determinations shall be based on the control performance and parameter data monitored during the performance test, supplemented if necessary by engineering assessments and the manufacturer's recommendations;
   (3) The owner or operator shall provide for the EPA Administrator's approval the rationale for selecting the monitoring parameters necessary to comply with Condition No. 18, and;
   (4) Provide for the Division of Air Resource Management (DARM) or the EPA Administrator's (as applicable) approval the rationale for the selected operating parameter value, and monitoring frequency, and averaging time. Include all data and calculations used to develop the value and a description of why the value, monitoring frequency, and averaging time demonstrate continuous compliance with the applicable emission standard.
[40 CFR 63.453(n)]

20. The permittee shall operate the control device in a manner consistent with the minimum or maximum (as appropriate) operating parameter value or procedure required to be monitored and established under Specific Conditions Nos. 15, 16.a., 17 through 19. Except as provided in Specific Condition No. 3, operation of the control device below minimum operating parameter values or above maximum operating parameter values established under this subpart or failure to perform procedures required by this subpart shall constitute a violation of the applicable emission standard of this subpart and be reported as a period of excess emissions. [40 CFR 63.453(o)].

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County:	Taylor

SPECIFIC CONDITIONS:

Recordkeeping Requirements

21. For each applicable enclosure opening, closed-vent system, and closed collection system, the permittee shall prepare and maintain a site-specific inspection plan including a drawing or schematic of the components of applicable affected equipment and shall record the following information for each inspection:
    (1) Date of inspection;
    (2) The equipment type and identification;
    (3) Results of negative pressure tests for enclosures;
    (4) Results of leak detection tests;
    (5) The nature of the defect or leak and the method of detection (i.e., visual inspection or instrument detection);
    (6) The date the defect or leak was detected and the date of each attempt to repair the defect or leak;
    (7) Repair methods applied in each attempt to repair the defect or leak;
    (8) The reason for the delay if the defect or leak is not repaired within 15 days after discovery;
    (9) The expected date of successful repair of the defect or leak if the repair is not completed within 15 days;
    (10) The date of successful repair of the defect or leak;
    (11) The position and duration of opening of bypass line valves and the condition of any valve seals; and
    (12) The duration of the use of bypass valves on computer controlled valves.
    [40 CFR 63.454(b)]

Test methods and procedures

22. Initial performance test. An initial performance test is required for all emission sources subject to the limitations in §§63.443, and 63.445, except those controlled by a combustion device that is designed and operated as specified in Specific Condition No. 2. [40 CFR 63.457(a)]

23. Vent *sampling port locations and gas stream properties*. For purposes of selecting vent sampling port locations and determining vent gas stream properties, required in §§63.443 and 63.445, the permittee shall comply with the applicable procedures specified in §63.457(b). [40 CFR 63.457(b)]

24. Detectable leak procedures. To measure detectable leaks for closed-vent systems as required in Specific Condition No.14.(b), the permittee shall comply with the requirements of §63.457(d).
    [40 CFR 63.457(d)]

25. Negative pressure procedures. To demonstrate negative pressure as required in Specific Condition No. 14(a) at process equipment enclosure openings, the permittee shall comply with the requirements of §63.457(e).
    [40 CFR 63.457(e)]

26. *HAP concentration measurements*. For purposes of complying with the requirements in §63.443, the permittee shall measure the total HAP concentration as one of the following:
    (1) As the sum of all individual HAPs; or
    (2) As methanol.
    [40 CFR 63.457(f)]

27. Bleaching HAP concentration measurement. For purposes of complying with the bleaching system requirements in §63.445, the permittee shall measure the total HAP concentration as the sum of all individual chlorinated HAP's or as chlorine. [40 CFR 63.457(h)]

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SPECIFIC CONDITIONS:

28. Vent gas stream calculations. To demonstrate compliance with the mass emission rate, mass emission rate per megagram of ODP, and percent reduction requirements for vent gas streams specified in §63.443 and 63.445, the permittee shall comply with the requirements of §63.457(i). [40 CFR 63.457(i)]

Terms/Definitions:

29. The term "immediately" as used in General Condition Number 8 of this permit shall mean "within 24 hours or the next working day". [Applicant Request dated 4/18/01]

30. The term "work site" as used in General Condition Number 12 of this permit shall mean "facility". [Applicant Request dated 4/18/01]

31. The term "monitoring information" as used in General Condition Number 14.b. shall include electronic data. [Applicant Request dated 4/18/01]

Submittals:

32. All reports, tests, notifications or other submittals required by this permit shall be submitted to the:

    Department of Environmental Protection
    Northeast District – Air Program
    7825 Baymeadows Way, Suite B200
    Jacksonville, Florida 32256
    Telephone: 904/448-4310
    Fax: 904/448-4366

33. The permittee shall submit an application for a Title V permit revision, or Title V permit renewal, as applicable, no later than November 30, 2002 [1] for the Low Volume High Concentration system, the pulping condensates, and the bleaching systems; and no later than November 30, 2006 [1] for the High Volume Low Concentration system. [Final Title V Permit No. 1230001-007-AV issued November 8, 2000]

[1] Note: If 40 CFR Part 63 is modified to allow for applicable time extension requests, the applicant may apply for an extension to the respective deadlines.

Executed in Jacksonville, Florida.

FILING AND ACKNOWLEDGEMENT
FILED, on this date, pursuant to S120.52 Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Dorothy Benefield 10/11/01
Clerk Date

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

Christopher L. Kirts, P.E.
District Air Program Administrator

Department of Environmental Protection

Northeast District
7825 Baymeadows Way, Suite B-200
Jacksonville, Florida 32256-7590

Jeb Bush
Governor

Colleen Castille
Secretary

PERMITTEE:

Buckeye Florida, Limited Partnership
One Buckeye Drive
Perry, Florida 32347

I.D. Number:	1230001
Permit/Cert Number:	1230001-018-AC
Date of Issue:	February 16, 2005
Expiration Date:	February 16, 2006
County:	Taylor
Latitude/Longitude:	30° 03' 59" N; 83° 33' 12" W
UTM:	E-(17) 256.7; N-3328.7
Project:	No. 1 Power Boiler

This permit is issued under the provisions of Chapter(s) 403, Florida Statutes, and Florida Administrative Code Rule(s) 62-210, 62-212, 62-296, 62-297 and 62-4. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawing(s), plans, and other documents attached hereto or on file with the department and made a part hereof and specifically described as follows:

PROJECT #018

Authorizes the use of the No. 1 Power Boiler (Emissions Unit 002) as the backup control device for NCG and TRS destruction for up to 960 hours per year. This is an increase from 480 hours per year authorized under Construction Permit No. 1230001-011-AC.

Noncondensible gases (NCGs) from the existing turpentine decanter, the turpentine underflow tank, and the digester accumulator lines are collected and tied into the existing Low Volume High Concentration (LVHC) gas collection system, then routed to the No. 1 Bark Boiler (primary device) or the pre-scrubber followed by the No. 1 Power Boiler (secondary/backup device for MACT) for combustion. TRS removal by the pre-scrubber has been confirmed by inlet and outlet testing to be least 50%.

Because the pre-scrubber will be operated as a permanent part of the backup LVHC control system, the increase in the allowable hours of NCG burning in the No. 1 Power Boiler will not result in an increase in SO_2 or SAM emissions. Estimates of HAP emissions have increase slightly over the values presented in the July 2000 MACT I permit application due to updated NCASI factors. TRS annual emissions have increased due to the increase in the allowable hours of NCG burning. The net emissions changes based on the revised LVHC NCG combustion conditions for the No. 1 Power Boiler are summarized in the table below.

In addition, in this permit, the Department corrects the rule citation in Specific Condition 4.b of Construction Permit No. 1230001-011-AC, as in incorrectly cites 40 CFR 60.283(a)(1)(iii) as the basis of the condition. None of the sources venting to the LVHC system (i.e., batch digester system, multiple effect evaporator system, and the turpentine system) are subject to 40 CFR 60 Subpart BB.

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Buckeye is required to continuously monitor and record the Total Reduced Sulfur (TRS) emissions incineration temperature at the No. 1 Bark Boiler. This requirement is based on an agreement between Mr. C.S. Aiken, Plant Manager of The Procter & Gamble Cellulose Company (Buckeye's predecessor), and the Bureau of Air Regulation. It was summarized in the Construction Permit Amendment letter for No. 1 Bark Boiler, dated May 17, 1990.

Because the No. 1 Power Boiler is the backup control device to the No. 1 Bark Boiler for TRS emissions, the TRS requirements are now consistent between the two boilers.

This permit also reduces the permitted TRS emissions at the No. 1 Bark Boiler based on the amended construction permit application pages received October 5, 2004.

Summary of the net emissions changes based on the revised LVHC NCG combustion conditions for the No. 1 Power Boiler (as a secondary control device):

		Pollutants Emission Rate (TPY)							
		SO2	NOx	CO	PM/PM10	TRS	VOC	SAM	HAPs
Total Proposed Modifications	▪ No. 1 Power Boiler as backup/secondary device and firing natural gas w/existing TRS scrubber as preliminary control device (MODE 1)*	124.1	---	---	---	1.09	---	7.6	0.22
	▪ No. 1 Power Boiler as backup/secondary device and firing fuel oil w/ existing TRS scrubber as preliminary control device (MODE 2)*	124.1	---	---	---	1.09	---	7.6	0.22
Existing Emissions	▪ No. 1 Power Boiler as backup/secondary device for LVHC NCG gases	0	---	---	---	0	---	0	0
	▪ Backup TRS+ Scrubber for LVHC NCG gases at the No. 1 Bark Boiler	---	---	---	---	50	---	0	5.9
Total of Existing Emissions		0	---	---	---	50	---	0	5.9
TOTAL NET CHANGE		124.1++	---	---	---	-48.9	---	7.6++	-5.7

* The No. 1 Power Boiler is the backup combustion device to comply with MACT I requirements for control of LVHC gases. It will be operated in either of two modes.

Mode 1: The No. 1 Power Boiler is the backup TRS combustion device while burning natural gas and LVHC. LVHC NCG gases are routed to the existing TRS scrubber (previously used at the No. 1 Bark Boiler) as a preliminary TRS control prior to combustion.

Mode 2: LVHC NCG gases will be routed to the existing TRS scrubber (previously used at the No. 1 Bark Boiler) as a preliminary TRS control, followed by combustion in the No. 1 Power Boiler during time periods when fuel oil and LVHC gases are burned in this boiler.

+ For existing emissions at the No. 1 Bark Boiler, the TRS Scrubber is the TRS Control backup control device

++ Above Significant Threshold. A Pollution Control Project (PCP) Exclusion was granted pursuant to 62-212.400(2)(a)2.b.

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FACILITY DESCRIPTION

This facility is a dissolving Kraft mill that consists of major activities areas such as: wood handling facility, pulping system, purification, chemical recovery, power house, drying/ converting/ warehouse, associated processes and equipment, and unregulated emissions units.

OPERATING LOCATION

Located east of US 19, south of SR 30, southeast of Perry, Taylor County.

RELEVANT DOCUMENTS

The documents listed below are the basis of the permit. They are specifically related to this permitting action. These documents are on file with the Department.

Air Construction Permit No. 1230001-011-AC
Application For Air Permit received April 28, 2004
Additional Information Received October 5, 2004
Comments from Applicant received January 4, 2005

PERMITTEE:

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GENERAL CONDITIONS:

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

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

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

4. This permit conveys not title to land or water, does not constitute State recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title.

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

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

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

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

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

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

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

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GENERAL CONDITIONS:

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

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

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

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

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

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

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

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

13. This permit also constitutes:

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

PERMITTEE:

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GENERAL CONDITIONS:

14. The permittee shall comply with the following:

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

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

c. Records of monitoring information shall include:

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

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

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Subsection A. This section addresses the following emissions unit(s).

E.U. ID No.	Brief Description
002	No. 1 Power Boiler with emissions vented through a common stack with E.U. 002, 003, 004, and 019. This boiler serves as a backup destruction device for noncondensable gases (NCGs) from the sources required to be controlled by 40 CFR Part 63, Subpart S (MACT I) and State TRS regulations. The gases are routed to a pre-scrubber prior to entering the boiler for destruction. The boiler shall be operated in this mode for a period not to exceed 960 hours per year.

ESSENTIAL POTENTIAL TO EMIT (PTE) PARAMETERS

A.1. **Hours of Operation**. The hours of operation are not limited.
[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C., Construction Permit No. 1230001-017-AC]

A.2. **Permitted Capacity.** The maximum heat input rate is 249 MMBtu/hr.
[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C., Construction Permit 1230001-017-AC]

A.3. **Methods of Operation**. This boiler may be fired with the following fuels:

1. Natural gas.
2. No.6 fuel oil with a sulfur content that shall not exceed 2.5% by weight and may include facility generated used oil.
3. No.2 fuel oil (typically used as a pilot fuel during startups, shutdowns, and malfunctions and for dry out fires after a water wash).
4. NCGs during periods when the boiler is being utilized for their destruction. Such operation shall occur for a period not to exceed 960 hours per year.
5. Facility-generated Tall Oil blended with No. 6 fuel oil. The sulfur content of the Tall Oil shall not exceed 0.05% by weight.

[Rule 62-213.410, F.A.C.; Rule 62-210.700, F.A.C.; Construction Permit No. 1230001-011-AC; Construction Permit No. 1230001-012-AC, Construction Permit No. 1230001-017-AC]

EMISSION LIMITATIONS AND PERFORMANCE STANDARDS

{Permitting Note: Unless otherwise specified, the averaging time for these conditions is based on the specified averaging time of the applicable test method.}

A.4. **Particulate Matter Emissions**. Particulate Matter emissions shall not exceed 47.9 lbs/hr and 209.96 TPY.
[Rule 62-296.406(2), F.A.C.; Rule 62-210.200(42), F.A.C.; BACT Determination dated 01-25-90; Construction Permit 1230001-017-AC]

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County:	Taylor

SPECIFIC CONDITIONS:

A.5. **Sulfur Dioxide Emissions**. Sulfur Dioxide emissions shall be limited to a maximum sulfur content of 2.5%, by weight and 671.9 lbs/hr and 2943.18 TPY.
[Rule 62-296.406(3), F.A.C.; Rule 62-210.200(42), F.A.C.; BACT Determination dated 01-25-90; Construction Permit 1230001-017-AC]

A.6. **Total Reduced Sulfur (TRS) Emissions**. When NCG gases are collected and routed to this Emissions Unit, TRS emissions shall not exceed 5 ppmvd @ 10% O2, as a 12 hour average; 2.28 lbs/hr and 1.1 TPY. TRS Emissions shall be incinerated for a minimum of 0.5 second and at a minimum of 1200°F.
[Rule 62-296.404(3)(f)1., F.A.C.; Construction Permit No. 1230001-011-AC; Construction Permit No. 1230001-012-AC]

A.7. **Visible Emissions**. Visible Emissions shall not exceed 20% opacity, except for one two-minute period per hour during which opacity shall not exceed 40 percent.

Visible emissions limits for Kraft pulp mill emissions units equipped with wet scrubbers shall be effective only if the visible emission measurement can be made without being substantially affected by moisture condensation. If the Department determines that visible emissions exceed 20 percent opacity, a special compliance test may be required in accordance with Rule 62-297.310(7)(b), F.A.C.

[Rule 62-296.406(1), F.A.C.; Rule 62-296.404(2)(b), F.A.C.; BACT Determination dated 01-25-90; Construction Permit 1230001-017-AC]

TEST METHODS AND PROCEDURES

A.8. **Sulfur Dioxide.** The permittee shall conduct sulfur dioxide emissions compliance test upon request by the Department in accordance with the requirements of Rule 62-297.310(7)(b), F.A.C. The test Method shall be EPA Method 6 incorporated and adopted by reference in Chapter 62-297, F.A.C. At all other times, compliance with the emission limit shall be demonstrated by complying with **Specific Condition A.12**.
[Rules 62-297.401(6), F.A.C.; Construction Permit No. 1230001-017-AC]

A.9. **Sulfur Content in Tall Oil.** The Permittee shall verify the sulfur content of the Tall oil by using appropriate testing methods on a quarterly basis. These records shall be maintained and reported on an annual basis.

[1]Testing required only if Tall Oil is fired during the quarter.

[Construction Permit No. 1230001-017-AC]

A.10. **TRS Emissions**. The test method for total reduced sulfur shall be EPA Method 16, or 16A incorporated and adopted by reference in Chapter 62-297, F.A.C. A compliance test shall be conducted prior to operation permit renewal during the federal fiscal year.

{Permitting Note: Buckeye shall use 80,000 acfm (design) to determine the lb/hr value in the event that an actual velocity measurement cannot be obtained during compliance testing}

[Rules 62-296.404(4)(e)3., 62-297.310(7)(a)1., (7)(a)3., (7)(a)4.b. F.A.C., 62-297.401(16), F.A.C.; Construction Permit No. 1230001-017-AC]

SPECIFIC CONDITIONS:

A.11. **<u>Visible Emissions.</u>** The test method for VE shall be DEP Method 9 incorporated and adopted by reference in Chapter 62-297, F.A.C., and shall be performed once each federal fiscal year. Visible emissions limits for Kraft pulp mill emissions units equipped with wet scrubbers shall be effective only if the visible emission measurement can be made without being substantially affected by moisture condensation. If the Department determines that visible emissions exceed 20 percent opacity, a special compliance test may be required in accordance with Rule 62-297.310(7)(b), F.A.C.
[Rule 62-296.404(2)(b), F.A.C.; Rule 62-297.401(9)(c), F.A.C.; Construction Permit No. 1230001-017-AC]

COMPLIANCE MONITORING

A.12. **<u>Particulate Matter and Sulfur Dioxide Emissions</u>**. In lieu of stack testing, a record shall be maintained of acceptable fuel oil analyses of all fuel oil received for at least a five-year period. This information shall be reported annually.

When fuel oil or a Tall Oil/fuel oil blend is fired in this power boiler, compliance with the permit limits (in lbs/hr) shall be determined by using the fuel oil or Tall Oil/fuel oil blend usage rate [the average for each contiguous 3-hour period (i.e., 0000-0300; 0300-0600; etc.)], fuel oil sulfur content and EPA matter emissions factors to calculate the particulate matter emissions and SO_2 emissions since the particulate matter and SO_2 are a function of fuel oil sulfur content. The equations are:

1. [[9.19 (S) + 3.22]/1000] x Fuel Oil/Tall Oil Usage [gallons per hr (3-hr avg)] = lbs PM per hour
2. [[157 (S)]/1000] x Fuel Oil/Tall Oil Usage [gallons per hr (3-hr avg)] = lbs SO_2 per hour

where S = weight percent sulfur (i.e., if 2.5%, insert 2.5)

{Permitting Note: The 3-hour averaging period is consistent with the manual stack test methods (when applicable), which are normally conducted as three separate 1-hour runs and averaged to determine compliance.}

Deleted: The maximum allowed fuel sulfur content may be used as the value for S in the equations.

[Permit No. AO62-230933; Construction Permit 1230001-017-AC]

A.13. **<u>TRS Pre-Scrubber Parameter Monitoring.</u>** Weak wash, from the lime mud washing system, (scrubbing media), shall be continuously added to the pre-scrubber at a minimum of 50 gallons per minute based on a 3-hour average. This flow set point shall be continuously monitored and verified on an annual basis. Monitoring records shall be maintained and available for inspection by the Department.

EXCESS EMISSIONS

A.14. **<u>Excess Emissions</u>**. Excess emissions resulting from startup, shutdown, or malfunction of any emission units 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 8 hours in any 24-hour period unless specifically authorized by the Department for longer duration.

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

PERMITTEE:

Buckeye Florida, Limited Partnership
One Buckeye Drive,
Perry, Florida 32347

I.D. Number:	1230001
Permit/Cert Number:	1230001-018-AC
Date of Issue:	February 16, 2005
Expiration Date:	February 16, 2006
County:	Taylor

SPECIFIC CONDITIONS:

A.15. Periods of excess emissions reported under 40 CFR Part 63, Subpart A shall not be a violation of 40 CFR 63.443(c) and (d), provided that the total time of excess emissions (excluding periods of startup, shutdown, or malfunction) divided by the total process operating time in a semi-annual reporting period does not exceed 4% for the No. 1 Power Boiler and No. 1 Bark Boiler combined.

[40 CFR 63.443(e)3; Construction Permit No. 1230001-011-AC; Construction Permit No. 1230001-012-AC, Construction Permit No. 1230001-017-AC]

CONTINUOUS MONITORING REQUIREMENTS

A.16. **TRS Emissions.** Total Reduced Sulfur (TRS) emissions incineration temperature shall be continuously monitored and recorded.
[Rule 62-296.404(5)(c), F.A.C.; Construction Permit No. 1230001-017-AC]

RECORDKEEPING AND REPORTING REQUIREMENTS

A.17. **Total Reduced Sulfur (TRS).** The Permittee shall submit a Total Reduced Sulfur (TRS) emissions and surrogate parameter data report to the Department postmarked by the 30th day following the end of each calendar quarter. The report shall comply with the requirements of Rule 62-296.404(6), F.A.C.
[Rule 62-296.404(6), F.A.C; Construction Permit No. 1230001-017-AC]

A.18. This emissions unit is also subject to Common Conditions C.1.- C.14.

PERMITTEE:

Buckeye Florida, Limited Partnership
One Buckeye Drive,
Perry, Florida 32347

I.D. Number:	1230001
Permit/Cert Number:	1230001-018-AC
Date of Issue:	February 16, 2005
Expiration Date:	February 16, 2006
County:	Taylor

SPECIFIC CONDITIONS:

Subsection B. The following specific conditions apply to the emissions unit listed below:

Emissions Unit No.	Description
004	No. 1 Bark Boiler

ESSENTIAL POTENTIAL TO EMIT (PTE) PARAMETERS

B.1. **Hours of Operation**: The hours of operation are not limited.
[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.; Construction Permit No. 1230001-017-AC]

B.2. **Permitted Capacity:** Permitted Capacity. The maximum heat input rate is 300 MMBtu/hr.
[Rule 62-210.200(PTE), F.A.C.; Construction Permit No. 1230001-017-AC]

B.3. **Methods of Operation**. This boiler may be fired with the following fuels:

1. Carbonaceous Fuel consisting of wood materials such as bark, chips, sawdust and other such wood fiber material.
2. No. 6 fuel oil with a sulfur content that shall not exceed 2.5% by weight (which may contain facility generated used oil) fired as primary fuel and during startups, shutdowns, malfunctions or temporary loss of bark.
3. No. 2 fuel oil fired typically as a pilot fuel during startups, shutdowns, malfunctions and for dry out fires after a water wash. Sulfur content that shall not exceed 0.5% by weight.
4. Natural gas fired typically as a pilot fuel during startups, shutdowns, malfunctions and for dry out fires after a water wash.
5. NCGs during periods when the boiler is being utilized for their destruction.
6. Facility-generated Tall Oil blended with No. 6 fuel oil. The sulfur content of the Tall Oil shall not exceed 0.05% by weight.

[Rule 62-213.410, F.A.C.; Rule 62-210.700, F.A.C.; Permit No. AC62-141927; Construction Permit No. 1230001-011-AC; Construction Permit No. 1230001-012-AC; Construction Permit No. 1230001-017-AC]

EMISSION LIMITATIONS AND PERFORMANCE STANDARDS

{Permitting Note: Unless otherwise specified, the averaging time for these conditions is based on the specified averaging time of the applicable test method.}

PERMITTEE:

		I.D. Number:	1230001
Buckeye Florida, Limited Partnership		Permit/Cert Number:	1230001-018-AC
One Buckeye Drive,		Date of Issue:	February 16, 2005
Perry, Florida 32347		Expiration Date:	February 16, 2006
		County:	Taylor

SPECIFIC CONDITIONS:

B.4. **Particulate Matter Emissions**. Particulate Matter emissions shall not exceed the following:

when firing only carbonaceous fuel:

0.158 lb/MMBtu and 207 TPY

when firing only No. 6 fuel oil or Tall Oil/Fuel Oil blend:

0.1 lb/MMBtu or 24.0 lb/hr

[Construction Permit No. 1230001-017-AC]

B.5. **Sulfur Dioxide Emissions**. Sulfur Dioxide emissions shall be limited to a maximum sulfur content of 2.5% by weight, in the No. 6 fuel oil and 675.1 lbs/hr and 2957 TPY.
[Permit No. AC62-141927; Construction Permit No. 1230001-017-AC]

B.6. **Total Reduced Sulfur (TRS) Emissions.** Total Reduced Sulfur emissions shall not exceed 5 ppmvd @ 10% O_2 as a 12-hour average; 2.43 lbs/hr (based on the test method time period) and 10.64 TPY. TRS Emissions shall be incinerated for a minimum of 0.5 second and at a minimum of 1200°F.
[Rule 62-296.404(3)(f)1., F.A.C.]

B.7. **Visible Emissions.** Visible emissions shall not exceed 30% opacity, except that up to 40% Opacity is permissible for not more than 2 minutes in any one hour.

Visible emissions limits for Kraft pulp mill emissions units equipped with wet scrubbers shall be effective only if the visible emission measurement can be made without being substantially affected by moisture condensation. If the Department determines that visible emissions exceed 20 percent opacity, a special compliance test may be required in accordance with Rule 62-297.310(7)(b), F.A.C.

[Rule 62-296.410(1)(b)1., F.A.C.; Rule 62-296.404(2)(b), F.A.C.; Construction Permit No. 1230001-017-AC]

TEST METHODS AND PROCEDURES

B.8. **Particulate Matter Emissions.** The test method for particulate matter emissions shall be EPA Method 5, incorporated and adopted by reference in Chapter 62-297, F.A.C. This compliance test shall be performed once each federal fiscal year.
[Rule 62-296.410(3), F.A.C.; Rules 62-297.401(5), F.A.C.; Permit No. AC62-141927; Construction Permit No. 1230001-017-AC]

B.9. **Sulfur Dioxide Emissions**. The test method for sulfur dioxide emissions shall be EPA Method 6 incorporated and adopted by reference in Chapter 62-297, F.A.C. This compliance test shall be performed once each federal fiscal year.
[Rule 62-297.401(6), F.A.C.; Permit No. AC62-141927; Construction Permit No. 1230001-017-AC]

SPECIFIC CONDITIONS:

B.10. **Sulfur Content in Tall Oil.** The Permittee shall verify the sulfur content of the Tall oil by using appropriate testing methods on a quarterly basis. These records shall be maintained and reported on an annual basis.

[1]Testing required only if Tall Oil is fired during the quarter.

[Construction Permit No. 1230001-017-AC]

B.11. **TRS Emissions.** The test method for total reduced sulfur emissions shall be EPA Method 16 or 16A incorporated and adopted by reference in Chapter 62-297, F.A.C. A compliance test shall be conducted prior to operation permit renewal during the federal fiscal year.
[Rule 62-297.401(16), F.A.C.; Permit No. AC62-141927; Rules 62-296.404(4)(e)3., 62-297.310(7)(a)1., (7)(a)3., (7)(a)4.b. F.A.C.; Construction Permit No. 1230001-017-AC]

B.12. **Visible Emissions.** The test method for visible emissions shall be DEP Method 9 incorporated and adopted by reference in Chapter 62-297, F.A.C., and shall be performed once each federal fiscal year.

Visible emissions limits for Kraft pulp mill emissions units equipped with wet scrubbers shall be effective only if the visible emission measurement can be made without being substantially affected by moisture condensation. If the Department determines that visible emissions exceed 20 percent opacity, a special compliance test may be required in accordance with Rule 62-297.310(7)(b), F.A.C.

[Rule 62-296.410(3), F.A.C.; Rule 62-297.401(9)(c), F.A.C.; Permit No. AC62-141927; Construction Permit No. 1230001-017-AC]

EXCESS EMISSIONS

B.13. **Excess Emissions**. Excess emissions resulting from startup, shutdown, or malfunction of any emission units 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 8 hours in any 24-hour period unless specifically authorized by the Department for longer duration.

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

[Construction Permit No. 1230001-017-AC]

CONTINUOUS MONITORING REQUIREMENTS

B.14. **TRS Emissions.** Total Reduced Sulfur (TRS) emissions incineration temperature shall be continuously monitored and recorded.
[Rule 62-296.404(5)(c), F.A.C.; Permit No. AC62-141927; May 17, 1990 Amendment; Construction Permit No. 1230001-017-AC]

RECORDKEEPING AND REPORTING REQUIREMENTS

B.15. Total Reduced Sulfur (TRS). The Permittee shall submit a Total Reduced Sulfur (TRS) emissions and surrogate parameter data report to the Department postmarked by the 30th day following the end of each calendar quarter. The report shall comply with the requirements of Rule 62-296.404(6), F.A.C.
[Rule 62-296.404(6), F.A.C.; Permit No. AC62-141927; Construction Permit No. 1230001-017-AC]

COMMON CONDITIONS

B.16. This emissions unit is also subject to Common Conditions C.1.- C.14.

PERMITTEE:

		I.D. Number:	1230001
Buckeye Florida, Limited Partnership		Permit/Cert Number:	1230001-018-AC
One Buckeye Drive,		Date of Issue:	February 16, 2005
Perry, Florida 32347		Expiration Date:	February 16, 2006
		County:	Taylor

SPECIFIC CONDITIONS:

Subsection C. The following specific conditions apply to the emissions unit listed below:

Emissions Unit No.	Description
002	No. 1 Power Boiler
004	No. 1 Bark Boiler

FLORIDA ADMINISTRATIVE CODE COMMON CONDITIONS

C.1. <u>**Compliance Test Procedures**</u>: Test procedures shall meet all applicable requirements of Chapter 62-297, F.A.C.

C.2. <u>**Compliance Test Notification**</u>: At least 15 days prior to the date on which each formal compliance test is due to begin, the permittee shall provide written notification of the test to the Air Compliance Section of Northeast District Department of Environmental Protection (DEP) Office. The notification must include the following information: the date, time, and location of each test; the name and telephone number of the facility's contact person who will be responsible for coordinating the test; and the name, company and telephone number of the person conducting the test.
[Rule 62-297.310(7)(a)9., F.A.C.]

C.3. <u>**Operation During Compliance Test**</u>: Unless otherwise stated in the applicable emission limiting standard rule, testing of emissions shall be conducted with the emissions unit operation at permitted capacity as defined in Specific Condition A.2. If it is impracticable to test at permitted capacity, an emissions unit may be tested at less than the minimum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test load until a new test is conducted. Once the 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)(b), F.A.C.]

C.4. <u>**Requirements for Annual Testing**</u>: The owner or operator shall meet all applicable requirements of Rule 62-297.310(4), F.A.C.
[Rule 62-297.310(4), F.A.C.]

C.5. <u>**Compliance Test Reports:**</u> Reports of the required compliance tests shall be submitted as soon as practical but no later than 45 days after the last test is completed. Each test report shall include the maximum input / production rate at which this source was operated since the most recent test.
[Rule 62-297.310(8),F.A.C.]

SPECIFI C CONDITIONS:

C.6. **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.
[Rule 62-297.310(7)(b), F.A.C.]

C.7. **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.
[Rule 62-297.310(5)(a), F.A.C.]

C.8. **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)(b), F.A.C.]

C.9. **Annual Operating Report**: The owner or operator shall submit an Annual Operating Report for Air Pollutant Emitting Facility (DEP Form No. 62-210.900(5)) to the Northeast District Department of Environmental Protection (DEP) Office annually pursuant to Rule 62-210.370(3), F.A.C.

COMMON CONDITIONS

C.10. This permit shall supercede previous construction permits issued for these emission units and activities only to the extent of incorporating the conditions of this permit.

C.12. Any revision(s) to a permit (and application) must be submitted to the Department, in writing, and approved by the Department prior to implementation.

C.13. The permittee shall submit an application for a Title V Permit Revision no later than 180 days after these emissions units commence operation under the terms of this permit.
[Rule 62-213.420(1)(a)5., F.A.C.]

C.14. All tests, notifications or other submittals required by this permit shall be submitted to the:

Department of Environmental Protection
Northeast District – Air Program
7825 Baymeadows Way, Suite B200
Jacksonville, Florida 32256
Telephone: 904/807-3300
Fax: 904/448-4363

PERMITTEE:

Buckeye Florida, Limited Partnership
One Buckeye Drive,
Perry, Florida 32347

I.D. Number:	1230001
Permit/Cert Number:	1230001-018-AC
Date of Issue:	February 16, 2005
Expiration Date:	February 16, 2006
County:	Taylor

SPECIFIC CONDITIONS:

Executed in Jacksonville, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

Christopher L. Kirts, P.E.
District Air Program Administrator

Department of Environmental Protection

Jeb Bush
Governor

Northeast District
7825 Baymeadows Way, Suite B200
Jacksonville, Florida 32256-7590

David B. Struhs
Secretary

October 8, 2001

NOTICE OF PERMIT

CERTIFIED-RETURN RECEIPT

Mr. Howard Drew, V. P., Wood Cellulose Manufacturing
Buckeye Florida, Limited Partnership
One Buckeye Drive
Perry, Florida 32348-7702

Dear Mr. Drew:

Taylor County - AP
Buckeye Florida, Limited Partnership
MACT I Compliance:
No. 2 Brown Stock Washer System
No. 4 Recovery Boiler
No. 4 Smelt Dissolving Tank
Nos. 1 and 2 Lime Slakers

Enclosed is Permit Number 1230001-014-AC to construct the subject air pollution emissions unit(s), issued pursuant to Section 403.087, Florida Statutes (FS).

Any party to this order has the right to seek judicial review of it under section 120.68 of the Florida Statutes, by filing a notice of appeal under rule 9.110 of the Florida rules of Appellate Procedure with the clerk of the Department of Environmental Protection in the Office of General Counsel, Mail Station 35, 3900 Commonwealth boulevard, Tallahassee, Florida, 32399-3000, and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate district court of appeal. The notice must be filed within thirty days after this order is filed with the clerk of the Department.

Executed in Jacksonville, Florida.

FILING AND ACKNOWLEDGEMENT
FILED, on this date, pursuant to §120.52 Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.
Dorothy Pennefeld 10/11/01
Clerk Date

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

Christopher L. Kirts, P. E.
District Air Program Administrator

CLK:RFS

cc: Carla Ferguson, Buckeye Florida, Limited Partnership
David A. Buff, P.E., Golder Associates, Inc.

OCT 12 2001

Department of Environmental Protection

Jeb Bush
Governor

Northeast District
7825 Baymeadows Way, Suite B200
Jacksonville, Florida 32256-7590

David B. Struhs
Secretary

PERMITTEE:

Buckeye Florida, Limited Partnership
One Buckeye Drive,
Perry, Florida 32347

I.D. Number:	1230001
Permit/Cert Number:	1230001-014-AC
Date of Issue:	October 8, 2001
Expiration Date:	October 8, 2006
County:	Taylor
Latitude/Longitude:	30° 03' 59" N; 83° 33' 12" W
UTM:	E-(17) 256.7; N-3328.7
Project:	MACT I Compliance: No. 2 Brown Stock Washer System No. 4 Recovery Boiler No. 4 Smelt Dissolving Tank Nos. 1 & 2 Lime Slakers

This permit is issued under the provisions of Chapter(s) 403, Florida Statutes, and Florida Administrative Code Rule(s) 62-210, 62-212, 62-296, 62-297 and 62-4. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawing(s), plans, and other documents attached hereto or on file with the department and made a part hereof and specifically described as follows:

For the installation and implementation of equipment necessary for compliance with the kraft pulping standards of 40 CFR Part 63, Subpart S (MACTI), the emission units are identified below:

Emission Unit 011: No. 4 Recovery Boiler
Emission Unit 023: No. 4 Smelt Dissolving Tank with a scrubber to control emissions
Emission Unit 025: Nos. 1 &2 Lime Slakers with a wet scrubber to control particulate matter emissions
No. 2 Brown Stock Washer System

The Pulping System – MACT I includes those sources regulated under MACT I: Nos. 1 and 2 Batch Digester systems, the Turpentine Recovery system (includes the turpentine Condenser, Decanter, Weir Box, and Underflow Tank), Multiple Effect Evaporator systems (Nos. 1-4), the Pulping Process Condensate Collection System, the No 1 and No. 2 Brown Stock Washers and associated filtrate tanks, foam towers, knotters, screens, and storage chests.

Project Description:

Buckeye Florida, Limited Partnership – Foley Mill, was granted a Pollution Control Project (PCP) Exclusion for this project pursuant to the requirements of Rule 62-212.400(2)(a)2.b, F.A.C.

Buckeye proposes to replace the existing 3-stage, rotary drum washer and decker at the No. 2 Mill Brown Stock Washing system with a new multiple-stage, pressure-type, brown stock washer with a rated capacity of 1100 metric tons (1213 short tons) ADUP per day.

The No. 2 Brown Stock Washing system after completion of the project, will consist of the following:

- Primary Knotters (pressure type) New
- Secondary Knotters (pressure type) New
- Knot and shives tank Existing
- Closed screening system New

PERMITTEE:

Buckeye Florida, Limited Partnership
One Buckeye Drive,
[?]y, Florida 32347

I.D. Number:	1230001
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Expiration Date:	October 8, 2006
County:	Taylor

Project Description Continued:

▪ Refined rejects chest	New
▪ Rejects refiner	New
▪ Pressure brown stock washer	New
▪ Filtrate Tank	Existing
▪ Pulp Storage Tanks	Existing

The filtrate from the new brown stock washer will allow for the recovery of additional black liquor solids (previously sewered) to be processed in the No. 4 Recovery Boiler, which in turn will affect the No. 4 Smelt Dissolving Tanks. Buckeye has requested an increase in the BLS loading to the No. 4 Recovery Boiler by 10,000 lb/hr, and the process rate at the lime slakers by 6751 lb/hr total solids. The potential increases in the No. 4 Lime Kiln, the chemical recovery area, and the causticizers will not require an increase in the current permitted rates for these sources. The project will reduce the emissions of hazardous air pollutants, volatile organic compounds, and total reduced sulfur compounds.

The new brown stock washer will be subject to the requirements of 40 CFR Part 60, Subpart BB. However, the facility received a temporary variance by EPA Region IV, from the requirement until April 16, 2006 due to the fact that this mill system will eventually be integrated into a single High Volume Low Concentration (HVLC) non-condensible gas system with the No. 1 Mill Brown Stock Washing System. The proposed changes to the No. 1 BSWS will be submitted by Buckeye at a later date.

The No. 2 Mill Brown Stock Washer System will also be subject to the requirements of 40 CFR 63, Subpart S.

Located: Route 17, Perry, Taylor County, Florida.

In accordance with:

Construction permit application received August 3, 2000
Additional Information Received November 13, 2000
Additional information received February 12, 2001
Comments received from Applicant dated April 19, 2001
Additional Information received June 4, 2001
Comments received from Applicant on August 24, 2001

PF TTTEE:

Buckeye Florida, Limited Partnership
One Buckeye Drive,
Perry, Florida 32347

I.D. Number:	1230001
Permit/Cert Number:	1230001-014-AC
Date of Issue:	October 8, 2001
Expiration Date:	October 8, 2006
County:	Taylor

Project Description Continued:

Summary of the net emissions changes as a result of this proposed project:

		Pollutants Emission Rate (TPY)											
		SO2	NOx	CO	PM	PM10	TRS	VOC	SAM	HAPs	Lead	Hg	Be
Total Proposed Modifications	▪ No. 2 Mill Brown Stock Washing System	—	—	—	—	—	2.83	37.60	—	16.70	—	—	—
	▪ No. 4 Recovery Boiler [2]	773.8	457.2	3106.6	496.7	385.4	20.7	45.7	38.7	36.75	2.0E-02	1.1E-02	9.8E-04
	▪ No. 4 Smelt Tank[2]	4.69	9.67	—	132.2	118.3	9.4	18.2	0.29	5.46	5.0E-03	5.3E-05	4.1E-05
	▪ No. 4 Lime Kiln [2]	136.88	299.76	56.12	87.60	87.60	11.56	32.30	8.38	3.42	4.1E-04	5.7E-04	1.0E-04
	▪ Lime Slaker System [2]	—	—	—	18.2	—	—	11.7	—	32.74	—	—	—
	▪ Lime Storage Bins	—	—	—	1.5	1.5	—	—	—	—	—	—	—
	▪ White Liquor Pressure Filter [2]	—	—	—	—	—	0.1	0.8	—	2.3	—	—	—
	▪ Lime Mud Pressure Filter [2]	—	—	—	—	—	0.1	1.0	—	4.7	—	—	—
Total of Future Emissions:		915.4	766.7	3162.7	736.2	592.8	44.7	147.3	47.4	102.0	2.5E-02	1.2E-02	1.1E-03
Existing Emissions	▪ Pulping Area General Decker[1]	—	—	—	—	—	12.8	15.4		20.3	—	—	—
	▪ Brown Stock Washing System[1]						68.6	107.8		247.5	—	—	—
	▪ No. 4 Recovery Boiler	632.4	368.4	2503.0	115.0	89.2	1.9	36.8	31.2	29.6	1.6E-02	8.8E-03	7.9E-04
	▪ No. 4 Smelt Tank	3.8	7.8	—	23.5	21.1	6.0	14.6	0.2	4.4	4.0E-03	4.3E-05	3.3E-05
	▪ No. 4 Lime Kiln	87.7	191.9	35.9	12.5	12.5	1.47	20.7	5.4	2.2	2.6E-04	3.7E-04	6.5E-05
	▪ Lime Slaker System	—	—	—	16.7	—	—	6.9	—	19.2	—	—	—
	▪ Lime Storage bins	—	—	—	1.3	1.3	—	—	—	—	—	—	—
	▪ White Liquor Pressure Filter	—	—	—	—	—	—	0.4	—	1.4	—	—	—
	▪ Lime Mud Pressure Filter	—	—	—	—	—	—	0.6	—	2.8	—	—	—
Total of Existing Emissions:		714.99	568.1	2538.9	169.0	124.1	90.8	203.2	36.8	327.4	2.0E-02	9.2E-03	8.9E-04
TOTAL NET CHANGE:		200.5[3]	198.6[3]	623.8[3]	567.2[3]	468.7[3]	-46.1	-55.9	10.6[3]	-225.4	5.2E-03	2.4E-03	2.3E-04

[1] To be removed from operation

[2] Based on proposed changes to both the No. 1 and No. 2 Brown Stock Washers

[3]Above Significant Threshold. A Pollution Control Project (PCP) Exclusion was granted pursuant to 62-212.400(2)(a)2.b.

PERMITTEE:

Buckeye Florida, Limited Partnership
One Buckeye Drive,
Perry, Florida 32347

I.D. Number:	1230001
Permit/Cert Number:	1230001-014-AC
Date of Issue:	October 8, 2001
Expiration Date:	October 8, 2006
County:	Taylor

GENERAL CONDITIONS:

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

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

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

4. This permit conveys not 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 no relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permitted to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department.

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

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

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

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

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

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

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County:	Taylor

GENERAL CONDITIONS:

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

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

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

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

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

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

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

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

13. This permit also constitutes:

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

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GENERAL CONDITIONS:

14. The permittee shall comply with the following:

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

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

c. Records of monitoring information shall include:

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

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

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SPECIFIC CONDITIONS:

The following conditions apply to Emission Units 046, Emission Point 01: No 2 Brown Stock Washing System:

1. The permittee shall comply with the requirements of 40 CFR Part 63, Subpart A- General Provisions as indicated in Table 1 of Subpart S.
[40 CFR 63.440(g)].

2. Total HAP emissions from the following equipment systems shall be controlled as specified in Specific Condition No. 3:

   - No. 2 Mill Brown Stock Washing System

3. Each equipment system listed in Specific Condition No. 2 shall be enclosed and vented into a closed-vent system and routed to a boiler or recovery furnace for control of total HAP emissions no later than the HVLC system compliance date of April 16, 2006. The enclosures and closed-vent system shall meet the requirements specified in Specific Condition No. 5. The HAP emission stream shall be introduced with the primary fuel or into the flame zone; or controlled in a boiler with a heat input capacity greater than or equal to 150 million British thermal Units per hour by introducing the HAP emission stream with the combustion air.
[40 CFR 63.443(c), 40 CFR 63.443(d)(4)(i) and (ii)].

4. Periods of excess emissions reported under Specific Condition No. 1 shall not be a violation of Specific Condition No. 3 provided that the time of excess emissions (excluding periods of startup, shutdown, or malfunction) divided by the total process operating time in a semi-annual reporting period does not exceed 4% for the boiler or recovery furnace. [40 CFR 63.443(e)(3)]

   Excess emissions due to startup, shutdown or malfunction are allowed for up to eight (8) hours in any 24 hour period unless otherwise requested and approved, provided effort is made to minimize emissions and duration in accordance with Rule 62-210.700 F.A.C.

Standards for enclosures and closed-vent systems:

5. Each enclosure and closed-vent system specified in Specific Condition No. 3 for capturing and transporting vent streams that contain HAP shall meet the following requirements no later than April 16, 2006.

   (a) Each enclosure shall maintain negative pressure at each enclosure or hood opening as demonstrated by the procedures specified in Specific Condition No. 10.

   (b) Each component of the closed-vent system used to comply with Specific Condition No. 3 that is operated at positive pressure and located prior to a control device shall be designed for and operated with no detectable leaks as indicated by an instrument reading of less than 500 parts per million by volume above background, as measured by the procedures specified in Specific Condition No. 9.

   (c) Each bypass line in the closed-vent system that could divert vent streams containing HAP to the atmosphere without meeting the emission limitations in §§63.443 and §§63.445 shall comply with one of the following requirements:

      (1) On each bypass line, the permittee shall install, calibrate, maintain, and operate according to manufacturer's specifications a flow indicator that provides a record of the presence of gas stream flow in the bypass line at least once every 15 minutes. The flow indicator shall be installed in the bypass line in such a way as to indicate flow in the bypass line; or

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SPECIFIC CONDITIONS:
Specific Condition No. 5 Continued:

(2) For bypass line valves these are not computer controlled, the permittee shall maintain the bypass line valve in the closed position with a car seal or a seal placed on the valve or closure mechanism in such a way that valve or closure mechanism cannot be opened without breaking the seal.

Note: Buckeye plans on demonstrating compliance with Specific Condition No.5(c)(1) by monitoring computer (DCS) controlled automatic valves with a continuous indication of any venting and the capability to record venting periods at least once every 15 minutes on each bypass line. The bypass lines are (2) two ten-inch vent collection lines located in the pulping and power operating departments.
[40 CFR 63.450]

Monitoring Requirements

6. Each enclosure and closed-vent system used to comply with Specific Condition No.5 shall comply with the following requirements no later than April 16, 2006:

(1) For each enclosure opening, a visual inspection of the closure mechanism specified in Specific Condition No. 5.(a) shall be performed at least once every 30 days to ensure the opening is maintained in the closed position and sealed.

(2) Each closed-vent system shall be visually inspected at least once every 30 days and at other times as requested by the Administrator. The visual inspection shall include inspection of ductwork, piping, enclosures, and connections to covers for visible evidence of defects.

(3) For positive pressure closed-vent systems or portions of closed-vent systems, demonstrate no detectable leaks as specified in Specific Condition No.5.(b) measured initially and annually by the procedures in Specific Condition No. 9.

(4) Demonstrate initially and annually that each enclosure opening is maintained at negative pressure as specified in Specific Condition No. 10.

(5) The valve or closure mechanism specified in Specific Condition No. 5.(c)(2) shall be inspected at least once every 30 days to ensure that the valve is maintained in the closed position and the emission point gas stream is not diverted through the bypass line.

(6) If an inspection required by Specific Conditions Nos. 6.(1) through 6.(5) identifies visible defects in ductwork, piping, enclosures or connections to covers required in Specific Condition No.5, or if an instrument reading of 500 parts per million by volume or greater above background is measured, or if enclosure openings are not maintained at negative pressure, then the following corrective actions shall be taken as soon as practicable.

(i) A first effort to repair or correct the closed-vent system shall be made as soon as practicable but no later than 5 calendar days after the problem is identified.

(ii) The repair or corrective action shall be completed no later than 15 calendar days after the problem is identified. Delay of repair or corrective action is allowed if the repair or corrective action is technically infeasible without a process unit shutdown or if the owner or operator determines that the emissions resulting from immediate repair would be greater than the emissions likely to result from delay of repair. Repair of such equipment shall be completed by the end of the next process unit shutdown.

[40 CFR 63.453(k)]

SPECIFIC CONDITIONS:

7. For each applicable enclosure opening, closed-vent system, and closed collection system, the permittee shall prepare and maintain a site-specific inspection plan including a drawing or schematic of the components of applicable affected equipment and shall record the following information for each inspection:
(1) Date of inspection;
(2) The equipment type and identification;
(3) Results of negative pressure tests for enclosures;
(4) Results of leak detection tests;
(5) The nature of the defect or leak and the method of detection (i.e., visual inspection or instrument detection);
(6) The date the defect or leak was detected and the date of each attempt to repair the defect or leak;
(7) Repair methods applied in each attempt to repair the defect or leak;
(8) The reason for the delay if the defect or leak is not repaired within 15 days after discovery;
(9) The expected date of successful repair of the defect or leak if the repair is not completed within 15 days;
(10) The date of successful repair of the defect or leak;
(11) The position and duration of opening of bypass line valves and the condition of any valve seals; and
(12) The duration of the use of bypass valves on computer controlled valves.
[40 CFR 63.454(b)]

8. Vent sampling port locations and gas stream properties. For purposes of selecting vent sampling port locations and determining vent gas stream properties, required in §§63.443, the permittee shall comply with the applicable procedures specified in §63.457(b). [40 CFR 63.457(b)]

9 Detectable leak procedures. To measure detectable leaks for closed-vent systems as required in Specific Condition No.5 (b), the permittee shall comply with the requirements of §63.457(d).
[40 CFR 63.457(d)]

10. Negative pressure procedures. To demonstrate negative pressure as required in Specific Condition No.5 (a) at process equipment enclosure openings, the permittee shall comply with the requirements of §63.457(e).
[40 CFR 63.457(e)]

The following conditions apply to Emission Units 011, The No. 4 Recovery Boiler:

11. Permitted Capacity. Upon installation of the No. 2 BSW, the maximum operating rate at this emissions unit shall not exceed 133,825 lbs (BLS)/hr, where BLS is Black Liquor Solids fired.

{Permitting note: The capacity limitations have been placed in each permit to identify the capacity of each emissions unit for purposes of confirming that emissions testing is conducted within 90-100 percent of the emissions unit's rated capacity (or to limit future operation to 110 percent of the test load), to establish appropriate limits and to aid in determining future rule applicability.}

[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.]

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		County:	Taylor

SPECIFIC CONDITIONS:

12. Methods of Operation. This boiler is fired with:

    1. Black liquor solids (BLS).

    2. No. 6 fuel oil with a sulfur content that shall not exceed 2.5% by weight (which may contain facility generated used oil) fired as primary fuel during startups, shutdowns, malfunctions or temporary loss of BLS.

    3. No. 2 fuel oil fired typically as a pilot fuel during startups, shutdowns, malfunctions and for dry out fires after a water wash. Sulfur content that shall not exceed 0.5% by weight. The usage of #2 fuel oil is limited to 50,000 gallons per year, unless otherwise requested.

    4. Natural gas fired typically as a pilot fuel during startups, shutdowns, malfunctions and for dry out fires after a water wash.

    [Rule 62-213.410, F.A.C.; Rule 62-210.700, F.A.C.; Title V Permit No. 120001-007-AV]

Emission Limitations and Standards

13. Particulate Matter Emissions shall not exceed 3 lbs/3000 lbs BLS; 113.40 lbs/hr (based on the test method time period) and 496.69 TPY. The amount of BLS fired in this recovery boiler shall be continuously monitored and recorded.
    [Final Title V Permit No. 1230001-007-AV]

14. Total Reduced Sulfur (TRS) emissions shall not exceed 5.0 ppmvd @ 8% O2 as a 12-hr avg.; 4.73 lbs/hr (based on the test method time period) and 20.71 TPY.
    [62-296.404(3)(c)b.]

15. Visible Emissions shall not exceed 45% opacity for a 6-minute average, except for up to 60% for one 6-minute period per hour is allowed.
    [Rule 62-296.404(1), F.A.C.; Final Title V Permit No. 1230001-007-AV]

Test Methods and Procedures.

16. Particulate Matter emissions shall be tested using EPA Method 5, incorporated and adopted by reference in Chapter 62-297, F.A.C.
    [Rule 62-296.404(4)(a)2., F.A.C.; Rules 62-297.401(5), F.A.C]

17. Visible Emissions shall be tested using EPA Method 9 incorporated and adopted by reference in Chapter 62-297.
    [Rule 62-296.404(4)(a)1., F.A.C.; Rules 62-297.401(9), F.A.C.]

Testing Frequency.

18. The permittee shall conduct a formal compliance test for pollutants identified in Specific Condition Nos. 13. and 15, within 60 days after the maximum operation rate for the No. 2 Mill Brown Stock Washer has been achieved, but not later than 180 days after its initial startup. At least 15 days prior to the date on which each formal compliance test is to begin, the permittee shall notify the Department of the date, time, and place of each test, and the test contact person who will be responsible for coordinating and having the test conducted.
    [FAC Rules 297.310(7)(a)1 and 297.310(7)(a)9]

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SPECIFIC CONDITIONS:

Monitoring Requirements.

19. Total Reduced Sulfur (TRS) emissions continuous monitoring shall comply with the applicable requirements in Rule 62-296.404(5), F.A.C.

Recordkeeping and Reporting Requirements.

20. Total Reduced Sulfur (TRS) emissions continuous monitoring report shall comply with the applicable requirements in Rule 62-296.404(6), F.A.C.

NSPS, Subpart BB Requirements:

21. The TRS gases from the brown stock washer shall be combusted in a boiler meeting the requirements of Specific Condition No. 22 no later than April 16, 2006, pursuant to the NSPS Variance granted by EPA Region IV on 12/12/00. [40 CFR 60.283(a)(1)]

Test Method and Procedures:

22. The TRS gases from the brown stock washer must be subjected to a minimum temperature of 1200°F and a 0.5-second residence time in either the recovery furnace or boiler used to combust the brown stock washer system gases.
[40 CFR 60.283(a)(1)(iii)]

23. The permittee shall comply with the applicable requirements of 40 CFR Part 60, Subpart A – General Provisions.

The following conditions apply to Emission Units 023, The No. 4 Smelt Dissolving Tank:

24. Permitted Capacity. The maximum allowed operation rate is 133,825 lbs (BLS)/hr, based on the maximum Black Liquor Solids fired in the No.4 Recovery Boiler.

{Permitting note: The capacity limitations have been placed in each permit to identify the capacity of each emissions unit for purposes of confirming that emissions testing is conducted within 90-100 percent of the emissions unit's rated capacity (or to limit future operation to 110 percent of the test load), to establish appropriate limits and to aid in determining future rule applicability.}

[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.]

25. Particulate Matter emissions shall not exceed the Process Weight Table (PWT); 30.19 lbs/hr (based on the test method time period) and 132.22 TPY, which is the existing permitted emission rate.
[Final Title V Permit No. 1230001-007-AV]

26. Total Reduced Sulfur (TRS) emissions shall not exceed 0.048 lb TRS/3000 lbs BLS as H_2S; 2.14 lbs/hr (based on the test method time period) and 9.4 TPY. The amount of black liquor solids fired in the recovery boiler associated with each SDT shall be continuously monitored and recorded.
[Rule 62-296.404(3)(d)1]

SPECIFIC CONDITIONS:

27. Visible Emissions shall not be greater than 20% opacity. Visible emissions limits for Kraft pulp mill emissions units equipped with wet scrubbers shall be effective only if the visible emission measurement can be made without being substantially affected by moisture condensation. If the Department determines that visible emissions exceed 20 percent opacity, a special compliance test may be required in accordance with Rule 62-296.404(2)(b), F.A.C. [Rule 62-296.404(2)(b), F.A.C.; Rule 62-297.310(7)(b), F.A.C.]

28. Particulate Matter emissions testing shall be by using EPA Method 5, incorporated and adopted by reference in Chapter 62-297, F.A.C.
[Rule 62-296.404(4)(c)1]

29. Visible Emissions (see Specific Condition No. 30) shall be tested using EPA Method 9, incorporated and adopted by reference in Chapter 62-297, F.A.C.
[Rule 62-296.404(2)(b), F.A.C.; Rule 62-297.401(9), F.A.C.]

30. Total Reduced Sulfur emissions testing shall be determined using EPA Method 16, 16A or 16B incorporated and adopted by reference in Chapter 62-297, F.A.C.
[Rule 62-296.404(4)(c)3. And 62-297.401(16), F.A.C.]

Monitoring Requirements.

31. The permittee shall comply with the monitoring requirements stated in the Final Title V Permit No. 1230001-007-AV for this emissions unit.

Testing Frequency.

32. The permittee shall conduct a formal compliance test for pollutants identified in Specific Condition Nos. 25. – 27., within 60 days after the maximum operation rate at which the No. 2 Mill Brown Stock Washer has been achieved, but not later than 180 days after its initial startup. At least 15 days prior to the date on which each formal compliance test is to begin, the permittee shall notify the Department of the date, time, and place of each test, and the test contact person who will be responsible for coordinating and having the test conducted.
[FAC Rules 297.310(7)(a)1 and 297.310(7)(a)9]

The following conditions apply to Emission Units 025, The Nos. 1 & 2 Lime Slakers:

33. Permitted Capacity. The maximum allowed operation rate is 243,000 lbs/hr of lime solids plus green liquor solids (60,886 and 182,114 lb/hr, respectively).

{Permitting note: The capacity limitations have been placed in each permit to identify the capacity of each emissions unit for purposes of confirming that emissions testing is conducted within 90-100 percent of the emissions unit's rated capacity (or to limit future operation to 110 percent of the test load), to establish appropriate limits and to aid in determining future rule applicability.}

[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.]

35. Particulate Matter Emissions shall not exceed 2.08 lbs/hr (based on the test method time period) and 9.13 TPY.
[Final Title V Permit No. 1230001-007-AV]

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SPECIFIC CONDITIONS:

35. Visible Emissions shall not be greater than 20% opacity. Visible emissions limits for Kraft pulp mill emissions units equipped with wet scrubbers shall be effective only if the visible emission measurement can be made without being substantially affected by moisture condensation. If the Department determines that visible emissions exceed 20 percent opacity, a special compliance test may be required in accordance with Rule 62-296.404(2)(b), F.A.C. Rule 62-296.404(2)(b), F.A.C.; Rule 62-297.310(7)(b), F.A.C.]

36. Particulate Matter Emissions. In lieu of particulate emissions testing, the scrubber water pressure shall be maintained at 20 psig or higher. Record the pressure at the start and end of all visible emissions compliance tests. [Final Title V Permit No. 1230001-007-AV]

37. Visible Emissions testing shall be by using EPA Method 9, incorporated and adopted by reference in Chapter 62-297, F.A.C.
[Rule 62-297.401(9), F.A.C.]

Continuous Monitoring Requirements

38. Particulate Matter Emissions surrogate parameter, the scrubber water pressure, shall be maintained at 20 psig or higher and monitored by a device with an accuracy of (+/-) 15 percent.
[Final Title v Permit No. 1230001-007-AV]

Recordkeeping and Reporting Requirements

articulate Matter Emissions surrogate parameter monitoring shall be reported with all visible emissions ompliance tests.
[Final Title V Permit No. 1230001-007-AV]

The following conditions apply to Emission Units 011, 023, 025, and 046:

40. The ID Number and Project Name for this source shall be used on all correspondences.

41. This permit shall supercede previous permits issued for these emission units and activities only to the extent of incorporating the conditions of this permit. Specifically as follows:

Emission Unit	Permit Number	Specific Condition Number(s)
No. 4 Recovery Boiler	Permit No. AO62-208309	1, 4
No. 4 Smelt Dissolving Tank	Permit No. AC62-141926	2, 3
Nos. 1&2 Lime Slakers	Permit No. AC62-143536	2

2. The hours of operation are not restricted for these emissions units, i.e. 8.760 hours/year.
[Final Title V Permit 1230001-007-AV]

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SPECIFIC CONDITIONS:

Terms/Definitions:

43. The term "immediately" as used in General Condition Number 8 of this permit shall mean "within 24 hours or the next working day". [Applicant Request dated 4/18/01]

44. The term "work site" as used in General Condition Number 12 of this permit shall mean "facility". [Applicant Request dated 4/18/01]

45. The term "monitoring information" as used in General Condition Number 14.b. shall include electronic data. [Applicant Request dated 4/18/01]

Submittals:

46. All reports, tests, notifications or other submittals required by this permit shall be submitted to the:

Department of Environmental Protection
Northeast District – Air Program
7825 Baymeadows Way, Suite B200
Jacksonville, Florida 32256
Telephone: 904/448-4310
Fax: 904/448-4366

47. The permittee shall submit an application for a Title V permit revision, or Title V permit renewal, as applicable, no later than November 30, 2006 [1] for the High Volume Low Concentration system.
[Final Title V Permit No. 1230001-007-AV issued November 8, 2000]

[1] Note: If 40 CFR Part 63 is modified to allow for applicable time extension requests, the applicant may apply for an extension to the respective deadlines.

Executed in Jacksonville, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

Christopher L. Kirts, P.E.
District Air Program Administrator

FILING AND ACKNOWLEDGEMENT
FILED, on this date, pursuant to §120.52 Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.
Dorothy Bessefield 10/11/01
Clerk Date

ATTACHMENT C

REVISED CONTEMPORANEOUS AND DEBOTTLENECKING EMISSIONS ANALYSIS AND PSD APPLICABILITY TABLES

TABLE 3-4
CONTEMPORANEOUS AND DEBOTTLENECKING EMISSIONS ANALYSIS AND PSD APPLICABILITY
PHASE II, BUCKEYE ENERGY PROJECT, BUCKEYE FLORIDA

Source Description	EU ID	Pollutant Emission Rate (TPY)											
		SO_2	NO_x	CO	PM	PM_{10}	$PM_{2.5}$	VOC	TRS	SAM	Lead	Mercury	Fluoride
PROJECTED ACTUAL EMISSIONS													
No. 2 Recovery Boiler w/ NDCE	006	343.41	318.81	879.78	129.37	92.24	64.42	18.16	14.24	15.27	3.39E-03	1.10E-04	0.024
BL Concentrator for No. 2 Recovery Boiler		15.01	--	--	--	--	--	0.63	0.15	0.67	--	--	--
No. 3 Recovery Boiler w/ NDCE	007	369.76	309.98	828.18	121.65	86.73	60.57	14.92	13.82	16.44	3.22E-03	1.24E-04	0.031
BL Concentrator for No. 3 Recovery Boiler		15.62	--	--	--	--	--	0.66	0.15	0.69	--	--	--
BL Storage Tank		--	--	--	--	--	--	0.48	0.79	--	--	--	--
No. 1 Power Boiler	002	839.08	322.58	91.61	63.31	55.17	37.73	6.00	--	37.30	4.59E-03	4.95E-04	0.105
No. 2 Power Boiler	003	0.65	305.37	91.61	8.29	8.29	8.29	6.00	--	--	5.45E-04	2.84E-04	--
No. 1 Bark Boiler	004	145.55	242.20	647.57	146.83	143.89	143.89	36.70	--	6.47	4.32E-02	7.34E-04	0.016
No. 2 Bark Boiler	019	183.94	523.76	1,413.54	390.93	383.11	383.11	80.10	--	8.18	9.42E-02	1.60E-03	0.019
Bark Handling System [a]		--	--	--	3.68	0.88	0.88	--	--	--	--	--	--
Total- Future Potential		**1,913.01**	**2,022.70**	**3,952.30**	**864.06**	**770.31**	**698.90**	**163.65**	**29.15**	**85.03**	**1.49E-01**	**3.35E-03**	**0.196**
BASELINE ACTUAL EMISSIONS													
No. 2 Recovery Boiler w/ DCE	006	613.59	245.03	243.63	73.61	56.52	33.58	41.98	16.71	27.00	4.93E-03	7.88E-05	0.024
BLO System for No. 2 Recovery Boiler		--	--	--	0.98	0.98	0.98	23.91	18.42	--	--	--	--
No. 3 Recovery Boiler w/ DCE	007	544.46	207.42	195.75	33.84	25.98	20.35	33.67	12.13	23.96	4.11E-03	8.19E-05	0.031
BLO System for No. 3 Recovery Boiler		--	--	--	0.80	0.80	0.78	19.16	15.04	--	--	--	--
No. 1 Power Boiler	002	585.88	107.09	14.38	41.48	35.69	18.81	0.86	--	25.78	2.69E-03	2.52E-04	0.075
No. 2 Power Boiler	003	0.07	33.43	9.23	0.91	0.91	0.84	0.60	--	--	5.49E-05	3.10E-05	--
No. 1 Bark Boiler	004	63.94	205.06	547.15	129.94	127.35	127.84	31.00	--	2.81	3.68E-02	6.23E-04	0.009
No. 2 Bark Boiler	019	70.09	455.61	1,226.69	345.96	339.04	346.93	69.51	--	1.75	8.20E-02	1.40E-03	0.012
Total- BASELINE ACTUAL		**1,878.03**	**1,253.65**	**2,236.84**	**627.52**	**587.27**	**550.10**	**220.69**	**62.30**	**81.30**	**1.31E-01**	**2.47E-03**	**0.152**
Increase Due to Project		**34.98**	**769.05**	**1,715.46**	**236.54**	**183.04**	**148.80**	**-57.04**	**-33.15**	**3.73**	**1.86E-02**	**8.81E-04**	**0.043**
PSD SIGNIFICANT EMISSION RATE		40	40	100	25	15	NA	40	10	7	0.6	0.1	3.0
Netting Triggered?		No	Yes	Yes	Yes	Yes	No	No	No	No	No	No	No
CONTEMPORANEOUS EMISSION CHANGES													
Tall Oil as Fuel: 1230001-017-AC (2/16/05)		-- [b]	--	--	--	--	-- [b]	-- [b]	-- [b]	-- [b]	-- [b]	-- [b]	-- [b]
No. 1 Power Boiler NCG/TRS Destruction 1230001-018-AC (2/16/05)		124.1 [b,c]	--	--	--	--	-- [b]	-- [b]	-48.9 [b]	7.6 [b,c]	-- [b]	-- [b]	-- [b]
No. 2 Brown Stock Washer MACT I Compliance 1230001-014-AC (Completed early 2006)		200.5 [b,c]	198.6 [c]	623.8 [c]	567.2 [c]	468.7 [c]	-- [b]	-55.9 [b]	-46.1 [b]	10.6 [b,c]	5.2E-03 [b]	2.4E-03 [b]	-- [b]
Total Contemporaneous Emission Changes		**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
TOTAL NET CHANGE		34.98	769.05	1,715.46	236.54	183.04	148.80	-57.04	-33.15	3.73	1.86E-02	8.81E-04	0.043
PSD SIGNIFICANT EMISSION RATE		40	40	100	25	15	NA	40	10	7	0.6	0.1	3.0
PSD REVIEW TRIGGERED?		No	Yes	Yes	Yes	Yes	No	No	No	No	No	No	No

[a] This emissions unit is not affected during Phase I of the Buckeye Energy Project, and so the projected actual emissions are equal to the baseline actual emissions.

[b] Project does not result in a significant emissions increase for this pollutant. Therfore, netting is not triggered for this pollutant. This pollutant is not included in the total contemporaneous emissions changes.

[c] A Pollution Control Project (PCP) exclusion was granted for this pollutant pursuant to Rule 62-212.400(2)(a)2.b., F.A.C. These emissions are therefore not included in the total contemporaneous emission changes.

TABLE 3-3
CONTEMPORANEOUS AND DEBOTTLENECKING EMISSIONS ANALYSIS AND PSD APPLICABILITY
PHASE I, BUCKEYE ENERGY PROJECT, BUCKEYE FLORIDA

Source Description	EU ID	Pollutant Emission Rate (TPY)											
		SO_2	NO_x	CO	PM	PM_{10}	$PM_{2.5}$	VOC	TRS	SAM	Lead	Mercury	Fluoride
PROJECTED ACTUAL EMISSIONS													
No. 2 Recovery Boiler w/ NDCE	006	343.41	318.81	879.78	129.37	92.24	64.42	18.16	14.24	15.27	3.39E-03	1.10E-04	0.024
BL Concentrator for No. 2 Recovery Boiler		15.01	--	--	--	--	--	0.63	0.15	0.67	--	--	--
BL Storage Tank		--	--	--	--	--	--	0.48	0.79	--	--	--	--
No. 3 Recovery Boiler w/ DCE [a]	007	544.46	207.42	195.75	33.84	25.98	20.35	33.67	12.13	23.96	4.11E-03	8.19E-05	0.031
BLO System for No. 3 Recovery Boiler [a]		--	--	--	0.80	0.80	0.78	19.16	15.04	--	--	--	--
No. 1 Power Boiler [a]	002	585.88	107.09	14.38	41.48	35.69	18.81	0.86	--	25.78	2.69E-03	2.52E-04	0.075
No. 2 Power Boiler [a]	003	0.07	33.43	9.23	0.91	0.91	0.84	0.60	--	--	5.49E-05	3.10E-05	--
No. 1 Bark Boiler [a]	004	63.94	205.06	547.15	129.94	127.35	127.84	31.00	--	2.81	3.68E-02	6.23E-04	0.009
No. 2 Bark Boiler [a]	019	70.09	455.61	1,226.69	345.96	339.04	346.93	69.51	--	1.75	8.20E-02	1.40E-03	0.012
Total- Future Potential		**1,622.86**	**1,327.43**	**2,872.99**	**682.30**	**622.00**	**579.96**	**174.08**	**42.34**	**70.24**	**1.29E-01**	**2.50E-03**	**0.152**
BASELINE ACTUAL EMISSIONS													
No. 2 Recovery Boiler w/ DCE	006	613.59	245.03	243.63	73.61	56.52	33.58	41.98	16.71	27.00	4.93E-03	7.88E-05	0.024
BLO System for No. 2 Recovery Boiler		--	--	--	0.98	0.98	0.98	23.91	18.42	--	--	--	--
No. 3 Recovery Boiler w/ DCE	007	544.46	207.42	195.75	33.84	25.98	20.35	33.67	12.13	23.96	4.11E-03	8.19E-05	0.031
BLO System for No. 3 Recovery Boiler		--	--	--	0.80	0.80	0.78	19.16	15.04	--	--	--	--
No. 1 Power Boiler	002	585.88	107.09	14.38	41.48	35.69	18.81	0.86	--	25.78	2.69E-03	2.52E-04	0.075
No. 2 Power Boiler	003	0.07	33.43	9.23	0.91	0.91	0.84	0.60	--	--	5.49E-05	3.10E-05	--
No. 1 Bark Boiler	004	63.94	205.06	547.15	129.94	127.35	127.84	31.00	--	2.81	3.68E-02	6.23E-04	0.009
No. 2 Bark Boiler	019	70.09	455.61	1,226.69	345.96	339.04	346.93	69.51	--	1.75	8.20E-02	1.40E-03	0.012
Total- BASELINE ACTUAL		**1,878.03**	**1,253.65**	**2,236.84**	**627.52**	**587.27**	**550.10**	**220.69**	**62.30**	**81.30**	**1.31E-01**	**2.47E-03**	**0.152**
Increase Due to Project		**-255.17**	**73.78**	**636.14**	**54.78**	**34.73**	**29.86**	**-46.61**	**-19.96**	**-11.06**	**-1.55E-03**	**3.12E-05**	**0.000**
PSD SIGNIFICANT EMISSION RATE		40	40	100	25	15	NA	40	10	7	0.6	0.1	3.0
Netting Triggered?		No	Yes	Yes	Yes	Yes	No	No	No	No	No	No	No
CONTEMPORANEOUS EMISSION CHANGES													
Tall Oil as Fuel: 1230001-017-AC (2/16/05)		-- [b]	--	--	--	--	-- [b]	-- [b]	-- [b]	-- [b]	-- [b]	-- [b]	-- [b]
No. 1 Power Boiler NCG/TRS Destruction 1230001-018-AC (2/16/05)		124.1 [b,c]	--	--	--	--	-- [b]	-- [b]	-48.9 [b]	7.6 [b,c]	-- [b]	-- [b]	-- [b]
No. 2 Brown Stock Washer MACT I Compliance 1230001-014-AC (Completed early 2006)		200.5 [b,c]	198.6 [c]	623.8 [c]	567.2 [c]	468.7 [c]	-- [b]	-55.9 [b]	-46.1 [b]	10.6 [b,c]	5.2E-03 [b]	2.4E-03 [b]	-- [b]
Total Contemporaneous Emission Changes		**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
TOTAL NET CHANGE		**-255.17**	**73.78**	**636.14**	**54.78**	**34.73**	**29.86**	**-46.61**	**-19.96**	**-11.06**	**-1.55E-03**	**3.12E-05**	**0.000**
PSD SIGNIFICANT EMISSION RATE		40	40	100	25	15	NA	40	10	7	0.6	0.1	3.0
PSD REVIEW TRIGGERED?		No	Yes	Yes	Yes	Yes	No	No	No	No	No	No	No

[a] This emissions unit is not affected during Phase I of the Buckeye Energy Project, and so the projected actual emissions are equal to the baseline actual emissions.

[b] Project does not result in a significant emissions increase for this pollutant. Therfore, netting is not triggered for this pollutant. The total for this pollutant is not included in the total contemporaneous emissions changes.

[c] A Pollution Control Project (PCP) exclusion was granted for this pollutant pursuant to Rule 62-212.400(2)(a)2.b., F.A.C. The total for this pollutant is not included in the total contemporaneous emissions changes.

ATTACHMENT D

NCASI REFERENCE DOCUMENT EXCERPTS

ncasi technical bulletin

NATIONAL COUNCIL OF THE PAPER INDUSTRY FOR AIR AND STREAM IMPROVEMENT, INC., 260 MADISON AVENUE, NEW YORK, N.Y. 10016

A STUDY OF PARTICULATE SIZE DISTRIBUTION IN EMISSIONS FROM CONTROLLED SOURCES IN THE KRAFT PROCESS

ATMOSPHERIC QUALITY IMPROVEMENT
TECHNICAL BULLETIN No. 94
MAY 1978

findings from individual company research projects, information generated by consultants and unpublished research conducted by outside organizations not specifically funded by a mill or company.

The third source of data, which enabled filling of information gaps, was developed by NCASI conducted sampling at selected or representative mills meeting current kraft mill emission standards.

A. Uncontrolled Kraft Recovery Furnace Emissions

More particle size sampling has been conducted on kraft recovery furnace emissions than possibly any other kraft mill source. Paul (47) reported results from a non-DCE kraft recovery furnace installation which indicated the uncontrolled particulate concentration level to be approximately 2.75 grains per DSCF during the interval of the particle sizing tests. This value is somewhat lower than the average value of 5.11 grains per DSCF with a range of 3.2 to 10.2 grains per DSCF noted in a survey by Henderson (48) on non-DCE kraft recovery boilers. The most probable reason for low levels of particulate concentration reported based on cascade impactor results is the occurrence of nozzle and wall losses in conjunction with particle bounce. The high concentrations encountered before control devices adversely affect impactor particle collection efficiencies and necessitate shorter sampling times due to overloading of the collection plates. A short sampling interval would decrease the probability of obtaining a representative sample. The particle size distribution relationship suggested by the data presented by Paul (47) is depicted in Figure 6 and represents the average of four sampling tests. The mass mean diameter, Dp_{50}, (the intercept of the curve with the 50% probability level) was found to correspond to 1.6 microns. The geometric standard deviation or polydispersity factor (a completely monodisperse aerosol would have a factor of 1.0 and would appear as a horizontal line on a log probability chart) was calculated to be 2.7 and the gas stream sampled was judged to be a relatively monodisperse particle population.

The bulk density of the dry particulate matter was given (47) as 5 to 10 lb/ft^3 (80 to 160 kg/m^3) which is much lower than the direct contact evaporator (DCE) kraft recovery furnace density values of 20 to 30 lb/ft^3 (320 to 480 kg/m^3). This in itself points to a substantial difference that is possible in particle characteristics. The difference should be kept in mind when attempting to relate particle size distributions for non-DCE and DCE kraft recovery furnace emissions.

Bosch, *et al.*, (49) and Pilat, *et al.*, (9) discussed results of the particle size analysis for emissions representative of an uncontrolled DCE kraft recovery furnace as measured using a University of Washington Mark I cascade impactor. The two distribution curves obtained are depicted in Figure 7. Several characteristics of these relationships are of interest. The mass mean diameter for the two tests averaged 1.0 μm. The polydispersity factor was a quite low 2.6 and approaching a monodisperse aerosol. Bosch, *et al.*,

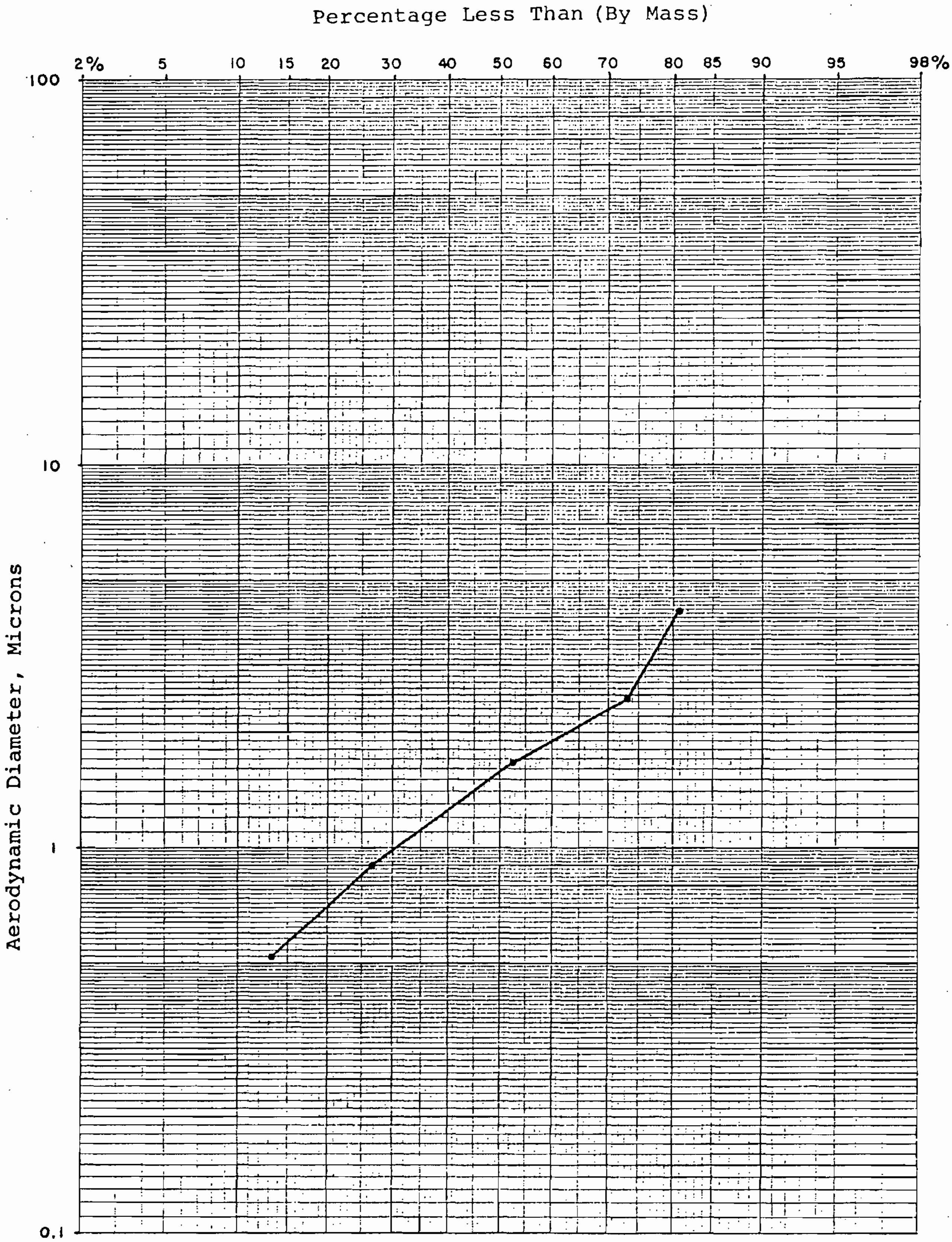

FIGURE 6

"TYPICAL" UNCONTROLLED PARTICLE SIZE DISTRIBUTION FOR NON-DCE KRAFT RECOVERY FURNACE (47)

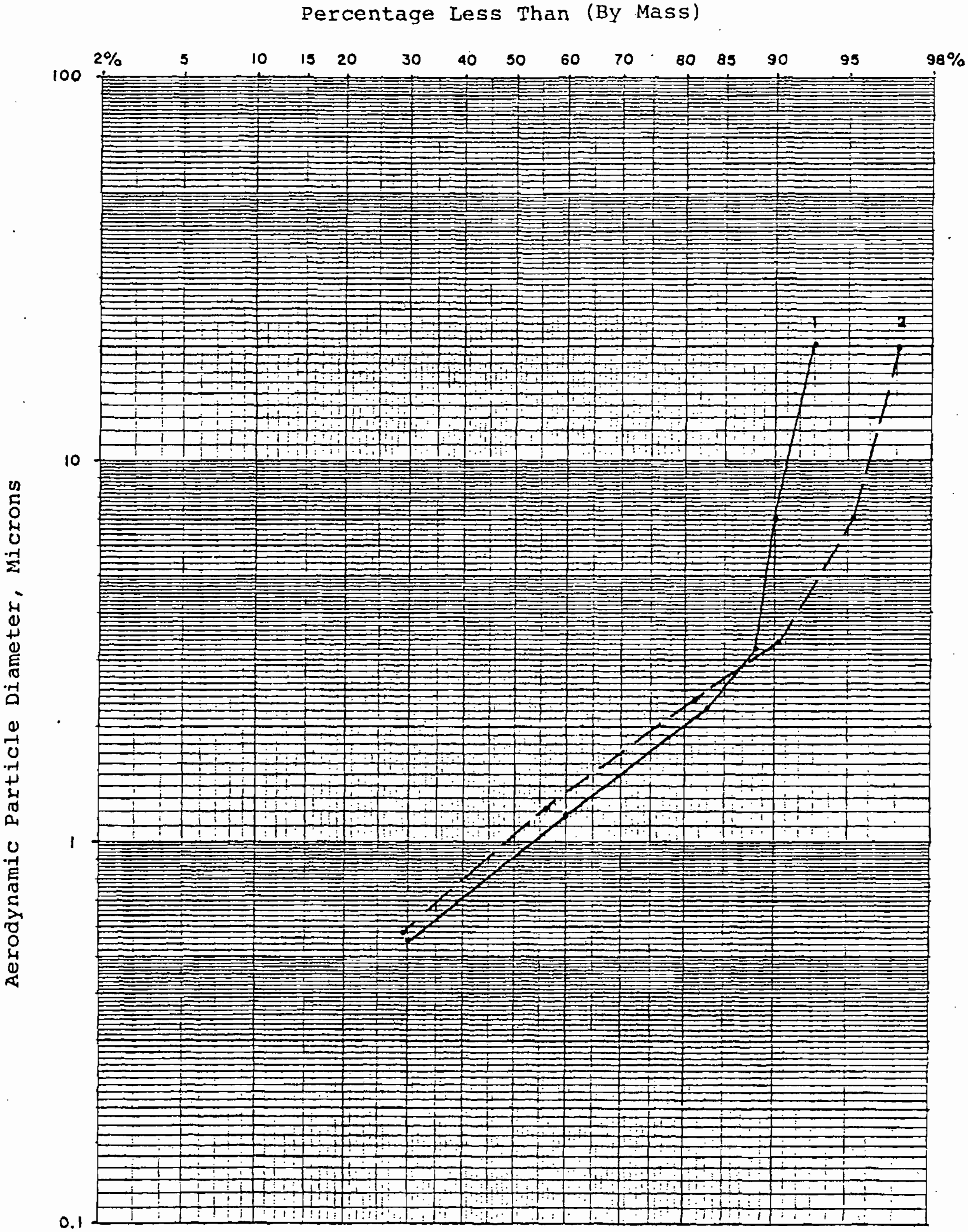

FIGURE 7

UNCONTROLLED DCE KRAFT RECOVERY FURNACE PARTICLE SIZE DISTRIBUTIONS (49)(9)

(49) indicated the presence of a black ash in the two samples obtained. Subsequent analysis showed the occurrence of a high predominance of carbonaceous black ash particles being much larger in overall size than the sodium-salt particles present. Visual inspection of the sample collected on impaction plates indicated two quite different particle populations existed in the recovery furnace exhaust. The non-linearity of Figure 7 was judged to be caused by multiple particle systems, each with a different size distribution with two populations identified as black ash and sodium salt. Separation of the uncontrolled emission samples qualitatively into ash and sodium salt fractions indicated the ash to have a mass mean diameter of roughly 30 μm and the sodium salt with a mass mean diameter of 0.9 μm. The sodium salt fraction of the emissions were found to be approximately 10% of the total particulate weight collected and was actually judged to be relatively independent of particle size. Both resulting distributions were extremely linear in nature suggesting the presence of just the two particle populations noted.

Collins, *et al.*, (50) extensively studied the composition and physical characteristics of kraft recovery furnace fume. He suggests that the fume content is largely composed of sodium sulfate (85%) and sodium carbonate with lesser quantities of sodium chloride, sodium sulfite and black ash. Inherent differences in volatilization temperatures of the various sodium salts, plus the entrainment of smelt particles and ignited black liquor droplets can result in overall changes in the sodium sulfate content. Furnace conditions will also play a major role in the sodium sulfate levels encountered with significant variation possible (51).

The work of Collins, *et al.*, (50) was substantiated by subsequent routine analysis performed by an NCASI member mill (52) on non-DCE kraft recovery furnace particulate emissions caught with a filter using EPA Method 5 procedures. Particulate concentration levels of about 3 pounds per ton of pulp were found to contain usually 80%, with occasionally up to 90%, of the total being sodium sulfate.

Larssen, *et al.*, (53) conducted numerous tests on the DCE kraft recovery furnace previously sampled by Bosch *et al.*, (49) using a University of Washington Mark I cascade impactor. Figure 8 represents the average of two of these tests at a particulate concentration measured at 2.2 grains per DSCF. The non-linearity indicative of multiple particle systems seen in previous size distributions was also apparent here. The mass mean diameter was approximately 0.8 microns associated with a geometric standard deviation of 2.4 which is basically representative of the lower straight portion of the graph as shown. The particle size calculations performed to construct Figure 8 assumed a constant aerodynamic particle density of 1.0 gram per cubic centimeter for all particle sizes.

Kutyna (54) measured the average uncontrolled emission for a Southeast United States DCE kraft recovery furnace using a Brink

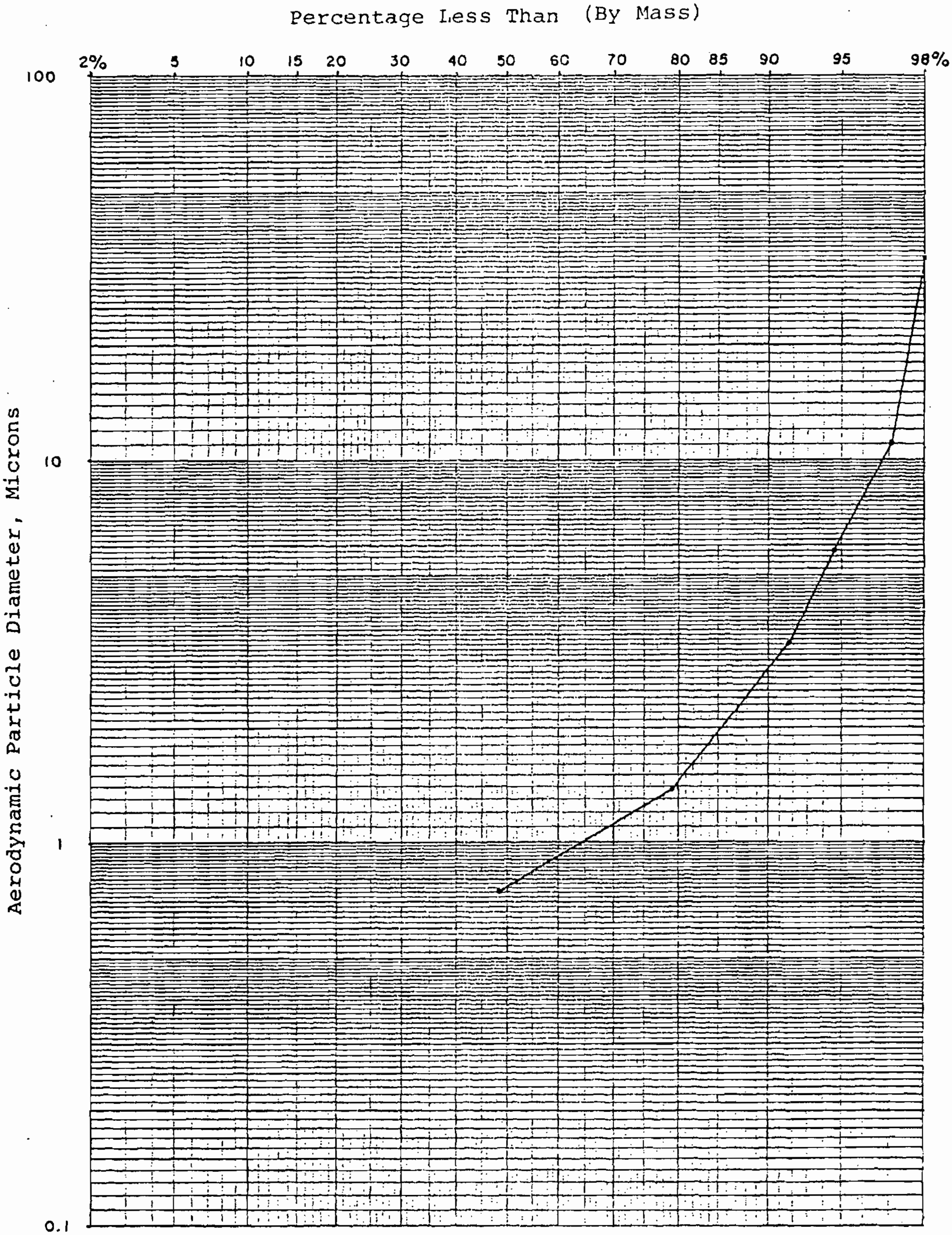

FIGURE 8

UNCONTROLLED PARTICLE SIZE DISTRIBUTION FOR NON-DCE KRAFT RECOVERY FURNACE (53) cascade impactor equipped with an in-line cyclone. The result as depicted in Figure 9 approximated linearity with a mass mean of 1.3 microns and a geometric standard deviation of 2. The reported electrostatic precipitator inlet particulate concentration was 2.44 grains per DSCF. The use of small nozzles and the cyclone pre-cutter was judged to have caused a slightly lower percentage of large particles and an estimated particulate concentration one-half that possible through use of larger nozzles. The cyclone pre-cutter used was found through calibration to be 50% efficient for particle diameters of 12.5 μm and 10% efficient for 5 μm particles.

B. Controlled Kraft Recovery Furnace Emissions

The size data corresponding to controlled kraft recovery furnace particulate emissions corresponded in all cases to installations equipped with electrostatic precipitators (ESP) and operating at an emission rate of less than 4 pounds per ton during the sampling interval.

A DCE kraft recovery furnace equipped with a two chamber, four field ESP (two, two field ESP's in series) was sampled with a modified Brink cascade impactor by Kutyna (54). The ESP outlet tests conducted were averaged with the mean dust concentration calculated to be 0.053 grains per DSCF. The result of averaging the outlet particle size distributions which were obtained through impactor sampling is shown as Figure 10. The mass mean diameter was determined to be roughly 7.3 microns with a corresponding geometric standard deviation of a somewhat high 8.2. Kutyna (54) suggested that ESP removal efficiencies for the larger particles was poor. He speculated, as did others (48,55), that the large particle fraction is formed during "rapping" of the last ESP field and resulting reentrainment. Gas stream bypass through the ESP was also proposed as a reason for the relative abundance of the larger particles. The use of grease on the collection plates of the impactor was judged to be another reason for the high mass mean diameter which resulted from the testing. Volatilization and scouring of grease would predominate on the lower impactor stage having the higher sampling gas velocities causing a shift of the particle size distribution relationship upward. This would result in a higher overall mass mean diameter based upon the weight loss from just the lower stages of the cascade impactor.

Particle size data obtained from studies by an NCASI member mill (56) for sampling accomplished with a University of Washington Mark III cascade impactor is presented in Figure 11. The unit sampled was a non-DCE kraft recovery furnace equipped with an electrostatic precipitator rated at a 99.8% efficiency. The total exhaust gas flow being treated corresponded to approximately 65% of the rated ESP capacity at the time of sampling. The particulate concentraton was reported as less than 0.01 grains per DCSF. The existence of multiple particle populations was quite evident from the non-linearity of the distributions illustrated in the figure. Contributions from two recovery furnace sources operating

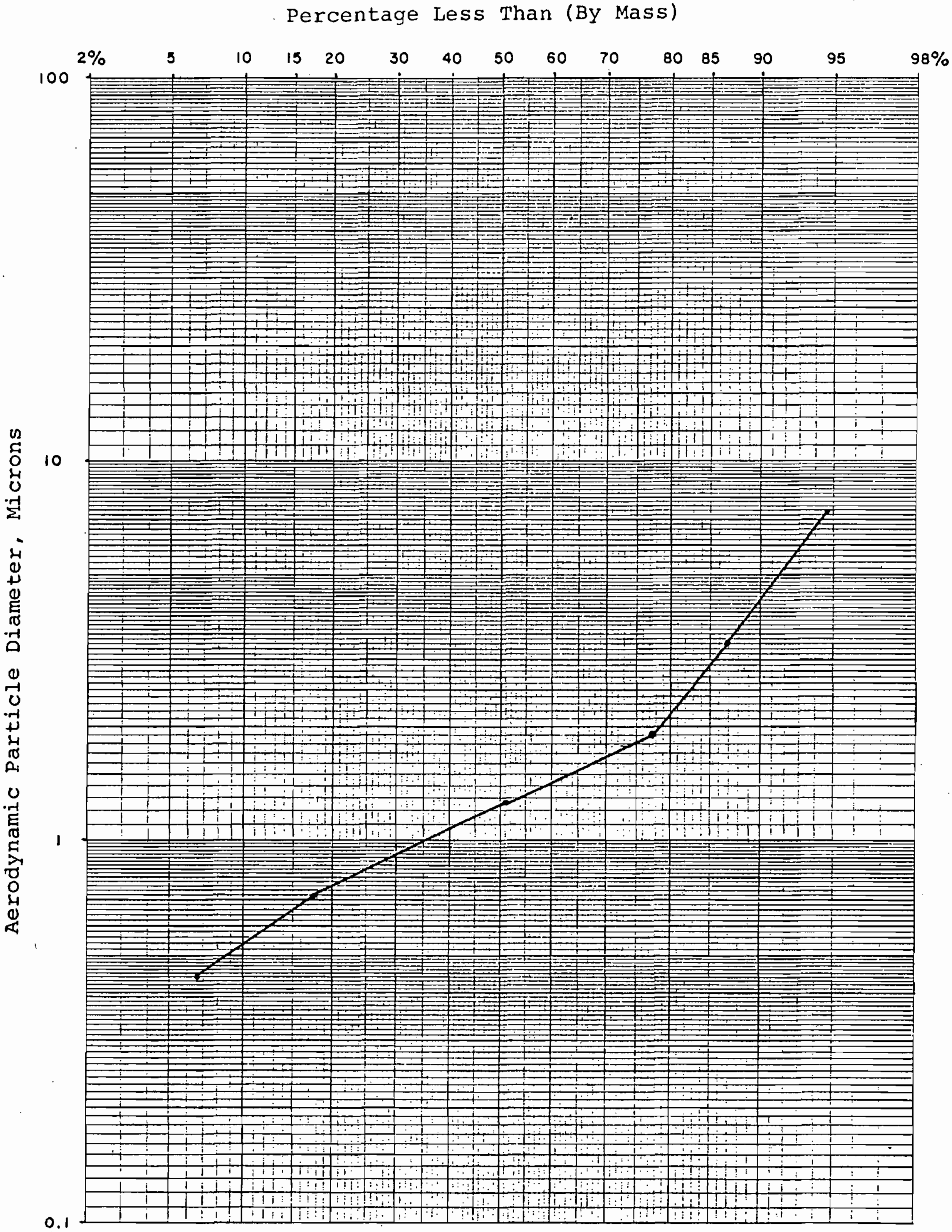

FIGURE 9

UNCONTROLLED PARTICLE SIZE DISTRIBUTION FOR DCE KRAFT RECOVERY FURNACES (54)

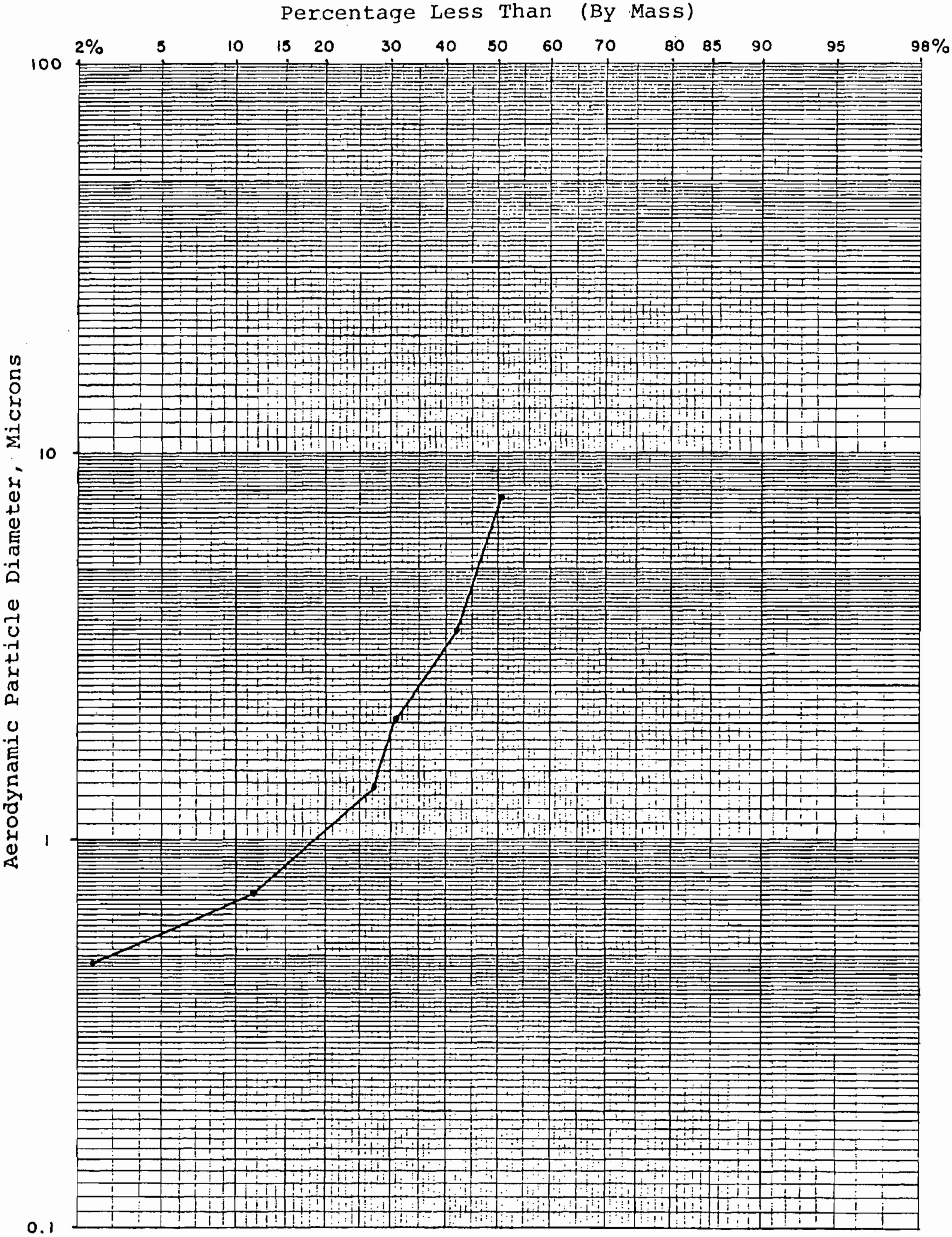

FIGURE 10

OUTLET PARTICLE SIZE DISTRIBUTION FOR DCE KRAFT RECOVERY FURNACE EQUIPPED WITH FOUR FIELD ELECTROSTATIC PRECIPITATOR (54)

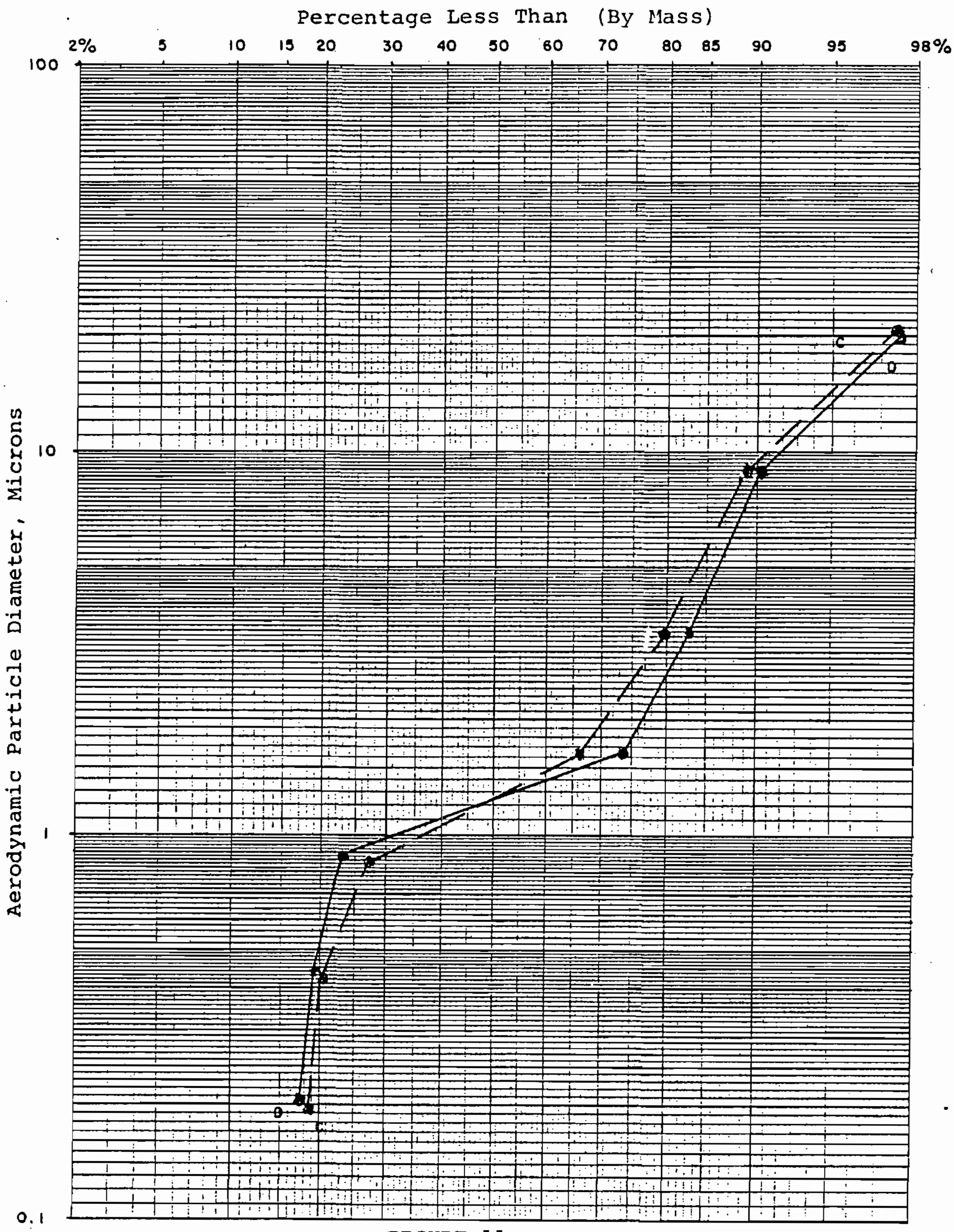

FIGURE 11

OUTLET PARTICLE SIZE DISTRIBUTION FOR NON-DCE KRAFT RECOVERY FURNACE EQUIPPED WITH TWO CHAMBER, FOUR FIELD ELECTROSTATIC PRECIPITATOR (56) at different control conditions to the total exhaust gas flow is the probable cause of the nonuniform nature of the distribution. Two sampling tests were completed giving an average mass mean diameter of 1.3 microns and a geometric standard deviation of roughly 6.5, indicating a somewhat polydisperse aerosol. The close proximity of the two distribution curves favorably addresses the reproducibility of the impactor sampling method for the testing at this site.

An NCASI member mill provided the following sampling data (57) for use in this summary as compiled by a University of Washington testing group. The Mark III impactor was utilized to conduct seven particle sizing tests over a ten day period on a non-DCE kraft recovery furnace which will be denoted as Site One for further reference. The results of these tests are presented in Figure 12. The furnace and two chamber four field electrostatic precipitator operating conditions were relatively steady during the time interval of the study as reflected by the grouping of the particle distributions. Table 4 presents the mass mean diameter, the geometric standard deviation and selected points from the size distribution for each test. The selected points (80% and 20% less than levels) indicate a scatter in the data with a range for the "80% less than" point of 3.9 to 48.0 microns. Averaging the values presented in the table resulted in 80% of the particle mass being less than 24.3 microns and 20% less than 0.6 microns. The mass mean diameter average corresponds to 50% of the particle mass less than 2.0 microns. Particulate concentration as measured by the Mark III impactor assembly varied from 0.002 to 0.032 with an average of 0.014 grains per DSCF.

NCASI conducted kraft recovery furnace particle size work was accomplished at three sites using a University of Washington Mark III cascade impactor. The sampling was done at three non-DCE electrostatic equipped kraft recovery furnaces. One installation designated as Site One was operating at less than 0.01 grains per DSCF, another (Site Two) at 0.04 grains per DSCF while the third (Site Three) represents a combined stack system (i.e. recovery furnace, lime kilns, smelt tank vent, and power boilers) operating at 0.07 grains per DSCF during the sampling interval.

The non-DCE kraft recovery furnace equipped with a four field ESP and operated at an emission concentration of less than 0.01 grains per DSCF during testing will be discussed first. Two impactor tests (58) were made at the designated Site One, which corresponds to the mill source discussed above and previously referenced (57). The predominance of the fine particle fraction is evident from Figure 13. The distributions obtained displayed a change from testing carried out three years before. Reasons for the shift to finer particles were not readily apparent from discussions with mill personnel. The primary modification to the system during this interval of time was the application of increased insulation to minimize heat losses prior to exit of recovery furnace exhaust gases from the stack. Stack gas temperature increased

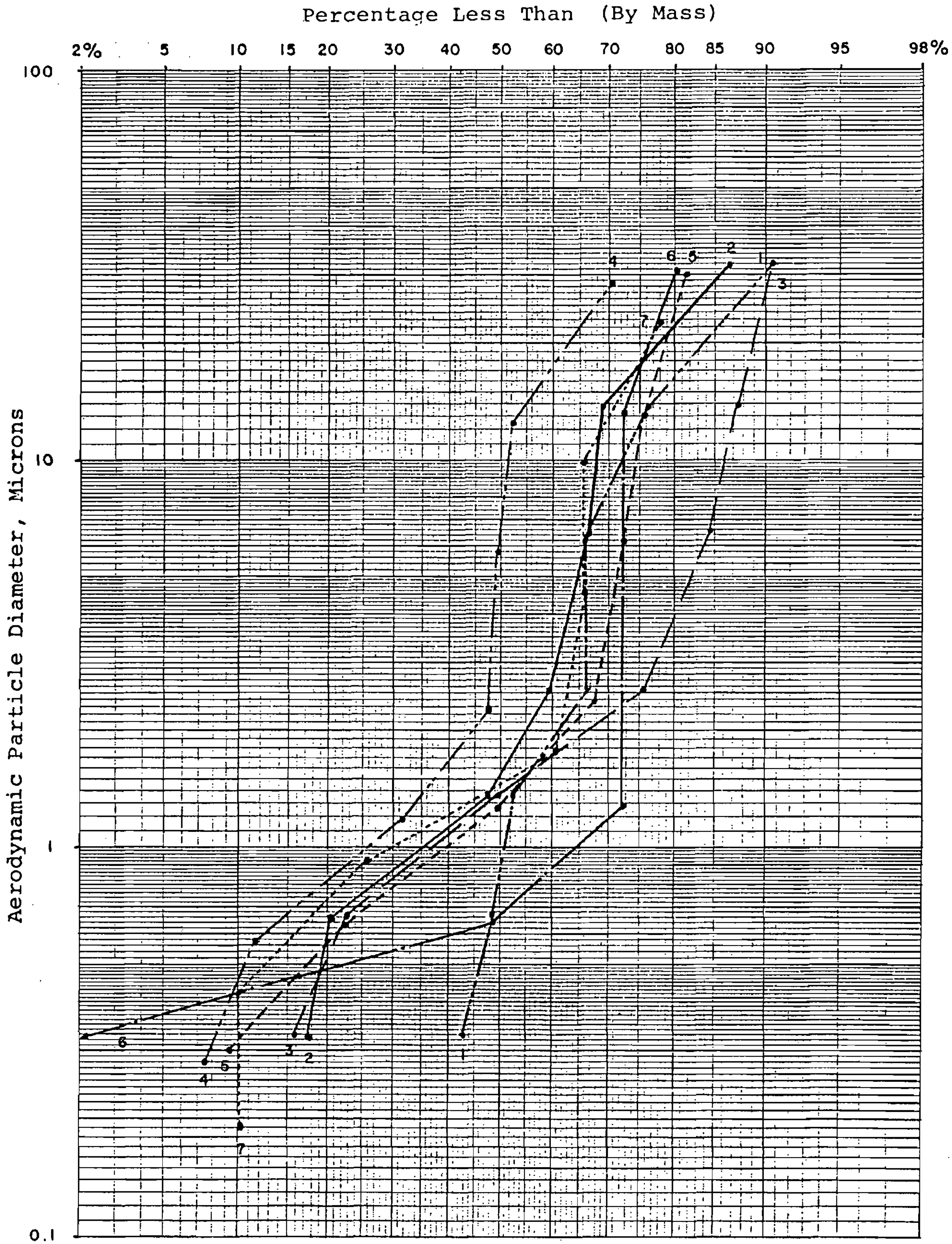

FIGURE 12

OUTLET PARTICLE SIZE DISTRIBUTIONS FOR NON-DCE KRAFT RECOVERY FURNACE, SITE ONE, EQUIPPED WITH TWO CHAMBER, FOUR FIELD ELECTROSTATIC PRECIPITATOR (57)

TABLE 4 PERTINENT PARTICLE SIZE PARAMETERS FOR FIGURE 12

Test Number	1	2	3	4	5	6	7	Average
Mass Mean Diameter, µm (Dp_{50})	0.8	1.6	1.4	7.0	1.3	0.7	1.5	2.0
Geometric Standard Deviation (σg)	24.1	17.7	4.3	10.1	9.9	10.3	7.7	12.0
Selected Points:								
Dp_{80} (µm)	16.5	22.0	3.9	48.0	23.5	30.0	26.0	24.3
Dp_{20} (µm)	-	0.6	0.5	0.8	0.6	0.5	0.7	0.6
Particulate Concentration grains/DSCF	0.002	0.006	0.029	0.03	0.021	0.004	0.006	0.014

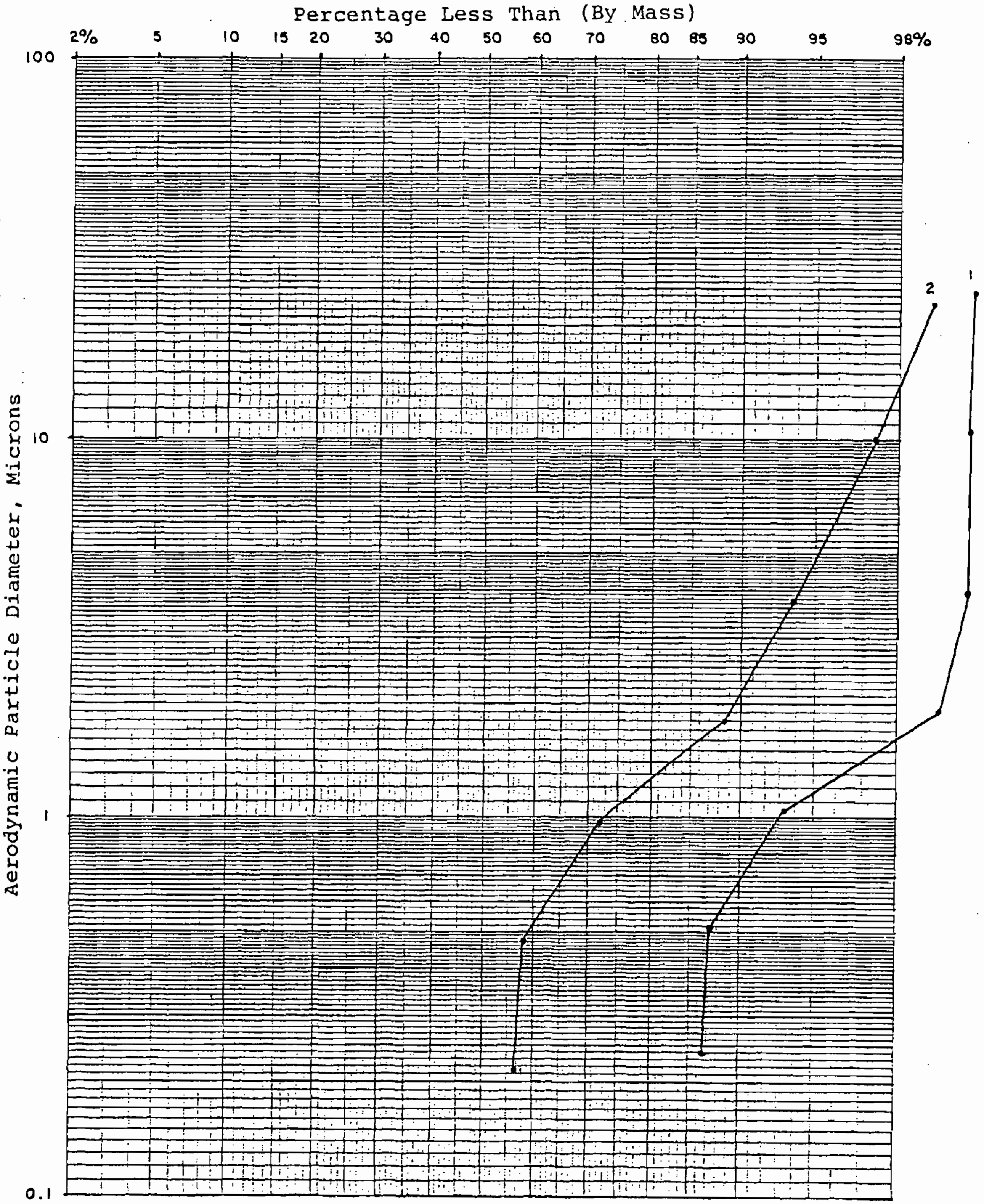

FIGURE 13

NCASI CONDUCTED PARTICLE SIZE DISTRIBUTIONS FOR NON-DCE KRAFT RECOVERY FURNACE, SITE ONE, EQUIPPED WITH TWO CHAMBER, FOUR FIELD ELECTROSTATIC PRECIPITATOR (58) from approximately 340°F (57) to a current level of about 390°F, supposedly based on this change alone. No change in stack gas moisture was noted.

Comparison of Figures 12 and 13 shows the shift which had occurred at Site One. The average mass mean diameter (Dp_{50}) noted in Table 4 of 2.0 microns corresponds to a Dp_{50} of less than 0.2 microns in the latest testing. The use of the University of Washington Mark III cascade impactor to obtain what might be termed complete size distribution curves for this source was questioned and may be beyond the capabilities of the measurement equipment. The requirement of a sampling interval of four hours at a flow rate of over 1 acfm to collect a representative impactor sample was reasoned to be an untenable procedure for such low total mass of fine particles. The particulate concentration for the two tests (58) averaged a low 0.002 grains per DSCF for these tests as compared to the higher level of 0.014 grains per DSCF for the previous testing.

The estimated geometric standard deviation (σg) for test "2" shown in Figure 13 was calculated to be 10.4. Roughly 90% of the particle mass was found to be less than 2.2 microns for the second sample while the first test measured 90% of the particle mass to be less than 0.7 microns. Table 4 further indicated the change in particle characteristics from the seven tests previously conducted with 80% of the particle mass being less than 24.3 microns as compared to Test "2" having 80% less than 1.3 microns. The obvious implication which was drawn from the very low particulate concentration and relatively fine particle distribution from the latest testing (58) was that an insignificant amount of mass of fine particles were produced from Site One during the sampling interval.

The non-DCE kraft recovery furnace source represented as Site Two was equipped with a two chamber, three field electrostatic precipitator at a Northwest U.S. location (59). A total of four University of Washington Mark III impactor tests were undertaken plus one microscopic comparison test. The results of the four impactor tests are depicted in Figure 14. Tests "1-3" were obtained during what may be termed normal operating conditions. The fourth test occurred during a time when the mill was experiencing slightly abnormal furnace operation and power regulation difficulties with the last field of the ESP. The greater percentage of large particles (i.e. 1 to 10 microns) reinforced the theory proposed earlier relative to particle reentrainment from the last field of the ESP under such conditions.

Supplementary recovery furnace exhaust gas and particle sizing characteristics are compiled in Table 5. The particle characteristics and the size distribution curves in Figure 14 indicate tests 1, 2 and 3 to be quite similar in every respect including particulate concentration which averaged 0.035 grains per DSCF. The average mass mean diameter and geometric standard

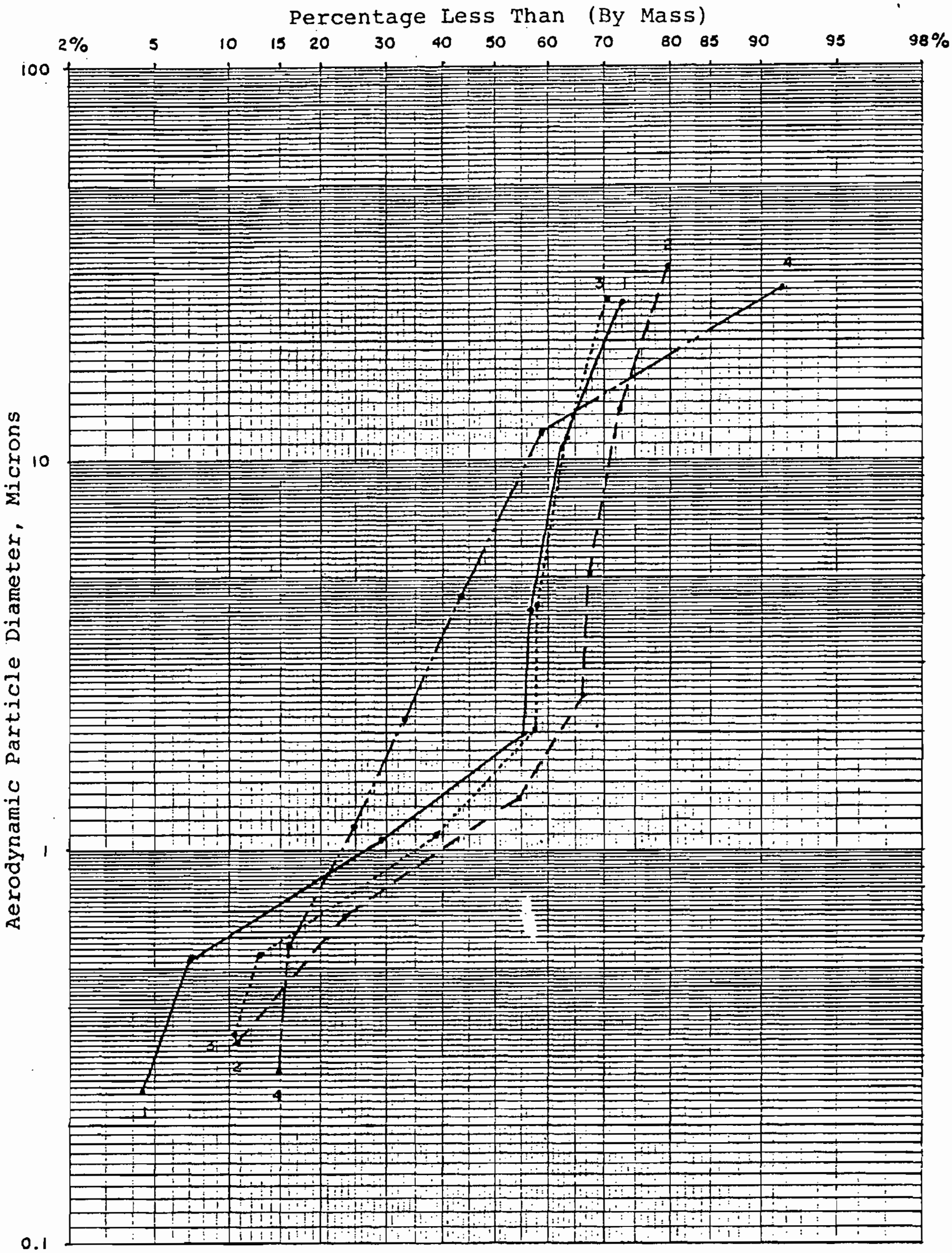

FIGURE 14

NCASI CONDUCTED PARTICLE SIZE DISTRIBUTIONS FOR NON-DCE KRAFT RECOVERY FURNACE, SITE TWO, EQUIPPED WITH TWO CHAMBER, FOUR FIELD ELECTROSTATIC PRECIPITATOR (59)

TABLE 5 NON-DCE KRAFT RECOVERY FURNACE STACK GAS AND PARTICLE SIZING CHARACTERISTICS FOR FIGURE 14

Test	Date	Particulate Concentration (grains/DSCF)	Dp_{50}, µm	Dp_{20}, µm	Dp_{80}, µm	σg	Stack Temp. (°F)	Sampling Time Interval, Hours
1	3/10/77	0.040	1.7	0.9	50	8.7	405	0.3
2	3/10/77	0.027	1.2	0.6	32.5	10.5	415	0.4
3	3/31/77	0.039	1.6	0.7	-	11.2	410	0.3
4	11/09/77	0.093	6.8	0.8	18.4	6.1	425	0.3

Dp_{50}: Mass mean particle diameter (at 50% probability)

σg: Geometric standard deviation or polydispersity factor

TABLE 6 COMBINED STACK PARTICLE SIZING CHARACTERISTICS FOR FIGURE 15

Test	Date	Particulate Concentration (grains/DSCF)	Dp_{50}, µm	Dp_{20}, µm	Dp_{80}, µm	σg	Stack Temp. (°F)	Sampling Time Interval, Hours
1	11/21/77	0.078	1.6	0.6	47.0	10.9	260	0.20
2	11/23/77	0.088	1.8	0.2	23.5	15.4	257	0.23
3	11/23/77	0.060	1.5	0.5	9.4	6.7	258	0.23

deviation for the three tests correspond to 1.5 microns and 10.1. Test 4 reflected the high impactor measured particulate concentration of 0.093 grains per DSCF measured with an equally high mass mean diameter of 6.8 microns. The opportunity was taken during the fourth test to obtain two filter samples suitable for optical microscopic analysis. These results will be presented in a later section.

The Site Three source (60) represents a combined stack system that included exhaust gas from a non-DCE kraft recovery furnace equipped with a two chamber, three field ESP followed by multiclones, two lime kilns equipped with: a common cyclone, venturi scrubber and flooded elbow, one smelt dissolving tank vent equipped with a white liquor scrubbing tank and two oil fired power boilers. A total of three Mark III particle size tests were conducted with the results as presented in Figure 15. Pertinent sizing parameters are given in Table 6. The size distribution curves of the three samples were relatively close and exhibited the non-linearity which usually corresponds to a multiple aerosol particle population. This characteristic was also visually evident from the collection plates. The first three plate inserts had particle deposits which were black in appearance, getting progressively lighter toward the finer particle sizes. Flyash from the uncontrolled power boilers was judged to be responsible for the black constitutent in the larger particle size fractions.

The average particulate concentration, mass mean diameter and geometric standard deviation were in order, 0.075 grains per DSCF, 1.6 microns and 11.0. In addition, 80% of the particle mass averaged less than about 26 microns with 20% less than approximately 0.4 microns.

C. Uncontrolled Lime Kiln Emissions

The next subject area which will be discussed concerns the uncontrolled particle properties of lime kiln emissions. The results of an extensive study to obtain data for the design of control facilities to reduce particulate emissions to compliance levels was carried out by NCASI member mill's technical departments (61) and made available for use in this report. Figure 16 displays particle size distributions for five samples obtained from a lime kiln with the mud feed on and the water spray that is located in the breeching before the venturi scrubber control device turned off. Tests 1, 2, 4, and 5 were conducted with a University of Washington Mark I impactor, while Test 3 incorporated a Mark III cascade impactor. The curves in Figure 16 indicate good consistency in the data that was compiled during a one day interval. Table 7 offers some additional testing parameters. The average particulate concentration was 11.0 grains per DSCF with 20% of the particle mass found to average less than 16.5 microns. The data suggested a majority of large particles. Chemical analysis performed on the samples indicated about 10% of the total catch was a sodium salt or derivative with most of the total quantity occupying the smallest

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CARBON MONOXIDE EMISSIONS FROM SELECTED COMBUSTION SOURCES BASED ON SHORT-TERM MONITORING RECORDS

TECHNICAL BULLETIN NO. 416

JANUARY 1984

range corresponded to about 3.0 to 5.0 percent oxygen on a wet gas basis as measured by an in situ oxygen meter. Too little excess air results in carbon monoxide generation because of incomplete combustion, whereas too much excess air reduces combustion zone flame temperature and gas residence time. Either a lack or abundance of oxygen in the flue gas resulted in increased carbon monoxide emission rates.

Figure 10 also shows the effect of auxiliary fuel firing on carbon monoxide emissions. Increased use of auxiliary fuel generally reduced carbon monoxide emission rates. Firing with oil in amounts greater than 50 percent the total energy input resulted in carbon monoxide emissions of less than 0.07 lb/10^6 Btu heat input for this boiler.

C. Carbon Monoxide Emissions from Kraft Recovery Furnaces

Presented in Table 5 are the average carbon monoxide emissions from each recovery furnace over the study period. These values are averages of between 88 and 168 hours of data for each furnace. Also presented in Table 5 are the medians of the 1 hr and 8 hr average emissions for each of the five recovery furnaces studied. Also listed in the table are the average oxygen concentrations measured on a wet basis in the exit gas from each recovery furnace. The average of all carbon monoxide emissions for each furnace ranged from 0.14 to 13.3 lb CO/10^3 lb bls fired, or from 0.43 to about 42 lb carbon monoxide per air dry ton (ADT) unbleached pulp produced. Medians of the 1 hr and 8 hr average data were less than the average data. This was a result of the exponential to logarithmic distribution of the data as illustrated by frequency distribution plots presented in Figures 13 to 17. In these figures the 1 hr and 8 hr average data plotted on Weibull frequency distribution paper show a variability in carbon monoxide emissions of up to two orders of magnitude for each of the recovery furnace studied. For the majority of the time, emissions were in the lower part of the range, but at less frequent intervals relatively high carbon monoxide emission rates were recorded. The level of 8 hr average carbon monoxide emission rates that were exceeded at least 1 percent of the time for furnaces A through E respectively were 0.8, 2.1, 1.3, 11, and 30 lb CO/10^3 lb bls.

A relationship between carbon monoxide emissions and exit gas oxygen concentrations was indicated. Figures 18 to 20 illustrate that at oxygen contents of less than 2 or 3 percent on a wet basis in the furnace exit gas, carbon monoxide emission rates increased rapidly. Similar figures are not shown for furnaces A and C because flue gas oxygen concentrations at these furnaces showed little variation during this study and no relationship to carbon monoxide emissions existed. The recovery furnace with emissions greater than 10 lb CO/10^3 lb bls was generally operating with less than 3 percent oxygen in the furnace exit gas. Recovery furnaces are normally operated at low excess combustion air to aid in reduction of sodium sulfate to sodium sulfide in the smelt.

TABLE 5 CARBON MONOXIDE EMISSION MEASURED AT FIVE KRAFT RECOVERY FURNACES

Furnace	Hours of Data	Total Average lb $CO/10^3$ lb bls	Total Average lb CO/ADT	Median of 1-hr Average CO Emissions	Median of 8-hr Average CO Emissions	Average O_2
A	88	0.14	0.43	0.06	0.08	3.8
B	120	0.60	1.8	0.33	0.48	3.3
C	136	0.64	3.1	0.56	0.60	3.2
D	168	1.87	5.9	0.95	0.96	3.1
E	152	13.3	42	12.2	12.5	2.8

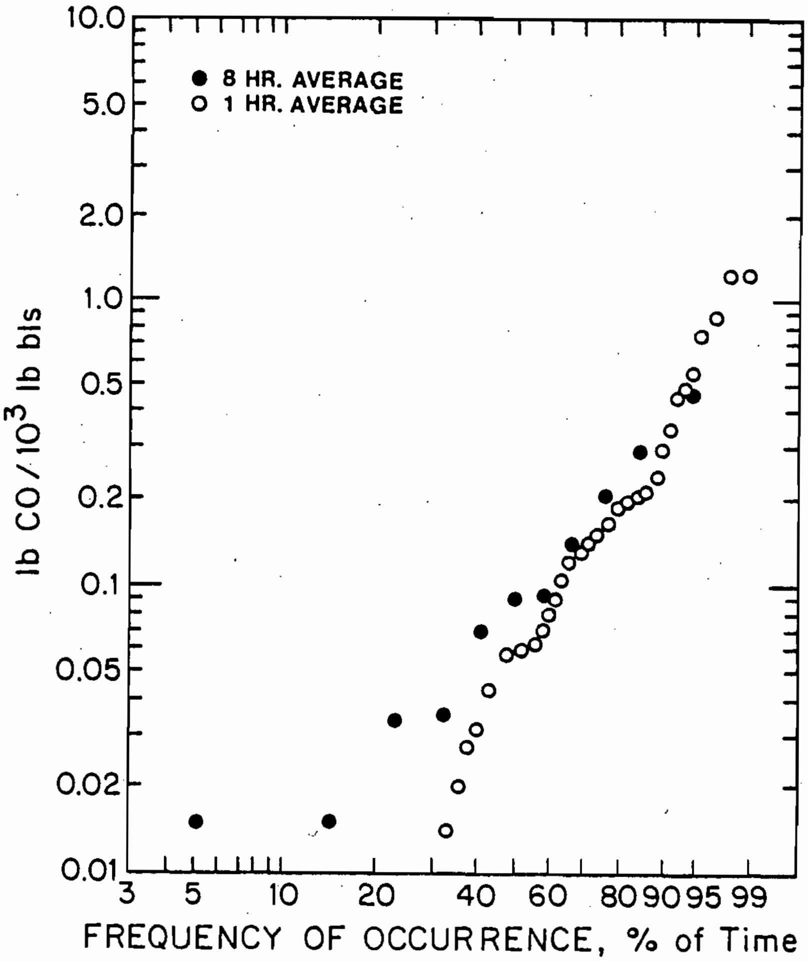

FIGURE 13

FREQUENCY OF CARBON MONOXIDE EMISSIONS FROM KRAFT RECOVERY FURNACE A

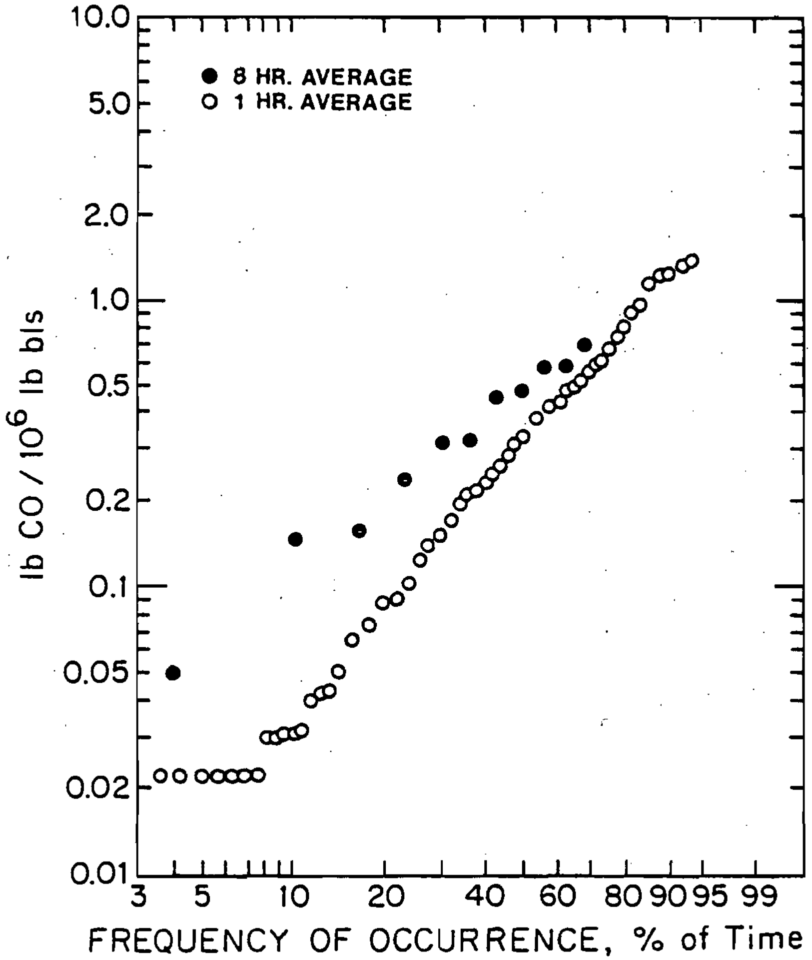

FIGURE 14

FREQUENCY OF CARBON
MONOXIDE EMISSIONS
FROM KRAFT RECOVERY FURNACE B

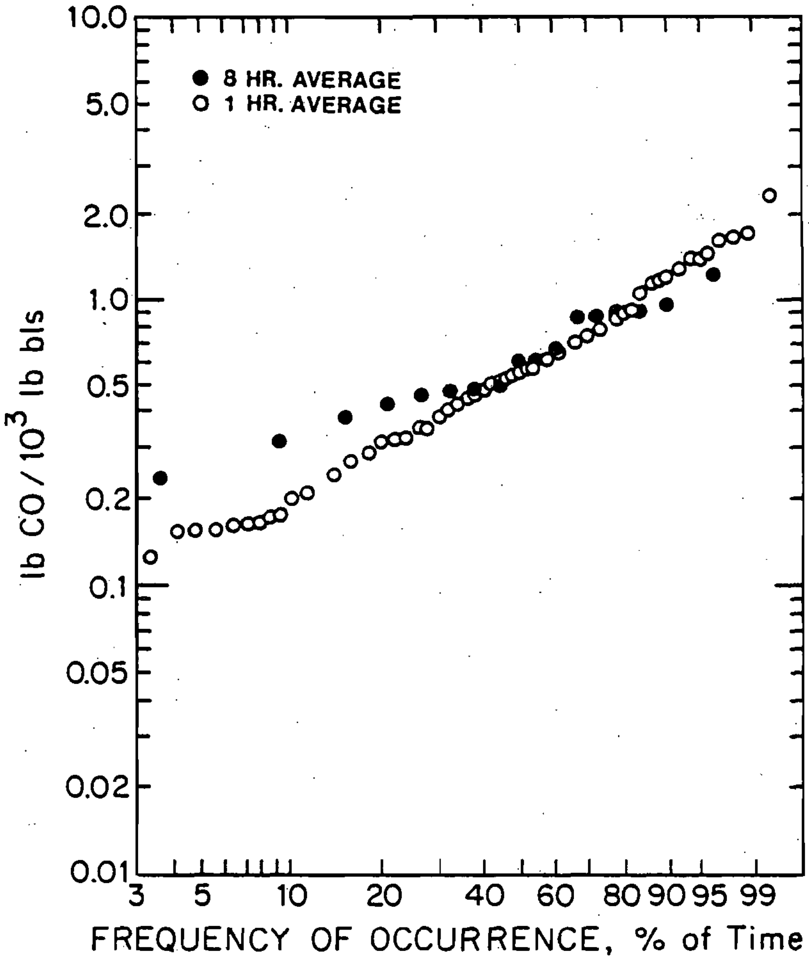

FIGURE 15

FREQUENCY OF CARBON
MONOXIDE EMISSIONS
FROM KRAFT RECOVERY FURNACE C

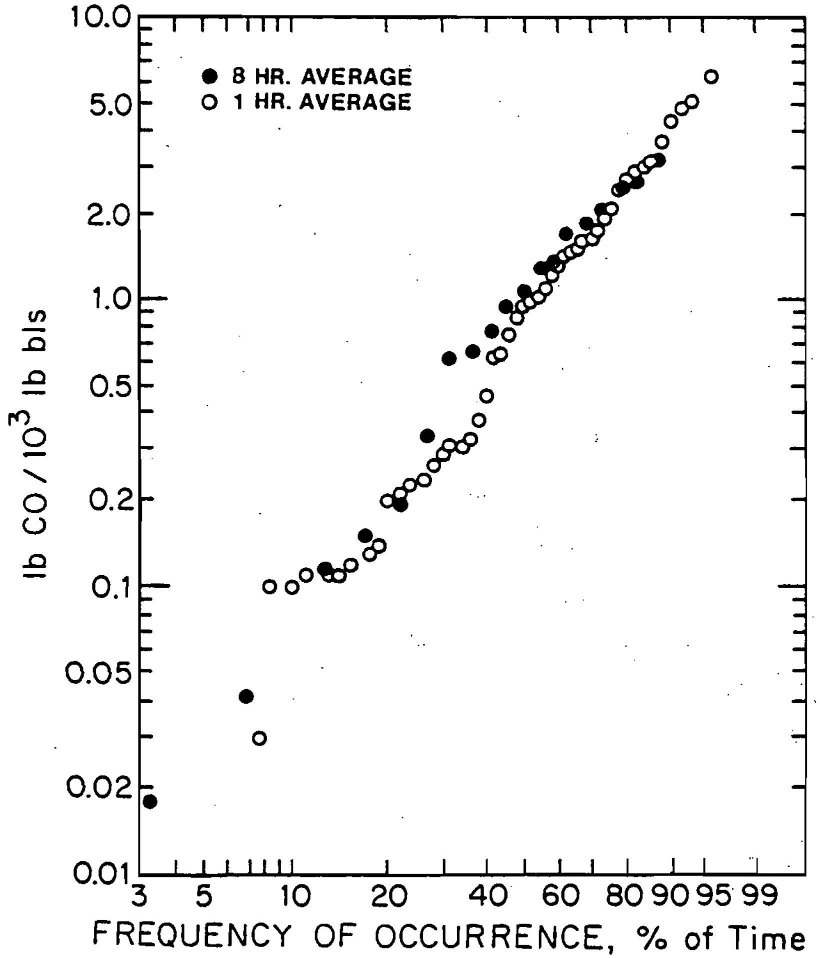

FIGURE 16

FREQUENCY OF CARBON
MONOIXDE EMISSIONS
FROM KRAFT RECOVERY FURNACE D

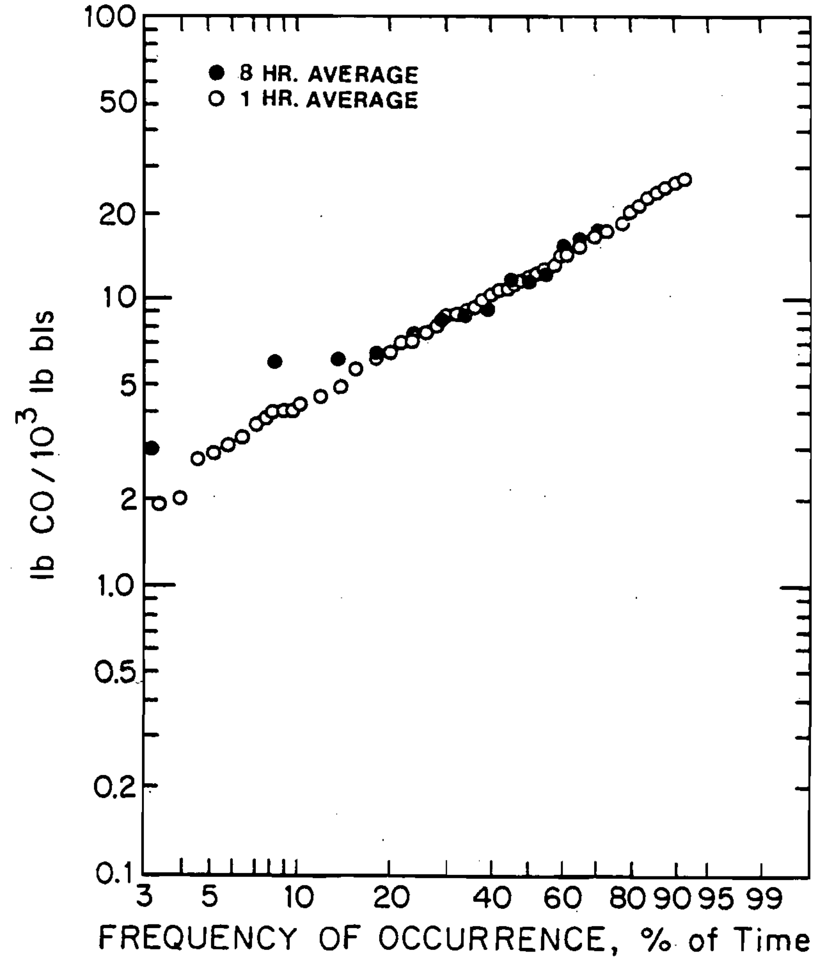

FIGURE 17

FREQUENCY OF CARBON
MONOXIDE EMISSIONS
FROM KRAFT RECOVERY FURNACE E

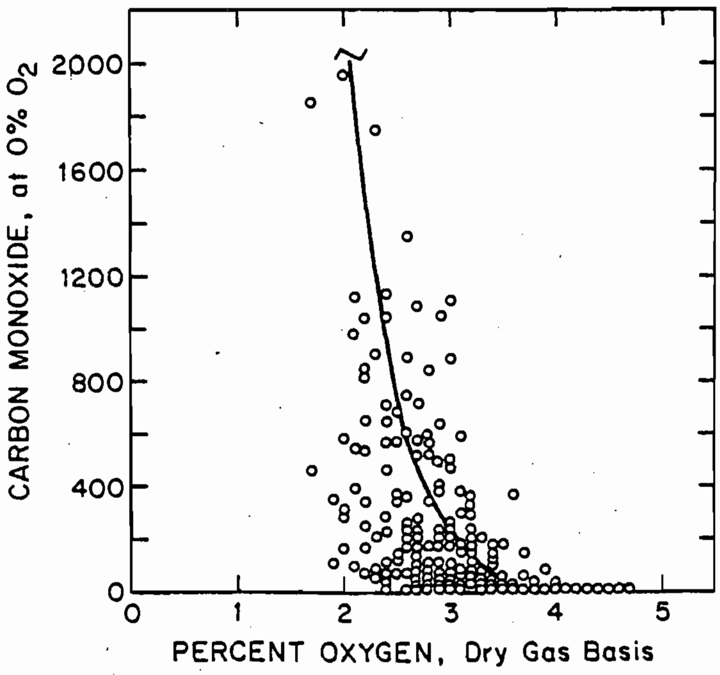

FIGURE 18

CARBON MONOXIDE EMISSIONS FROM KRAFT RECOVERY FURNACE B EXPRESSED AS ppm CORRECTED TO 0 PERCENT O_2 AS A FUNCTION OF STACK GAS OXYGEN CONCENTRATIONS

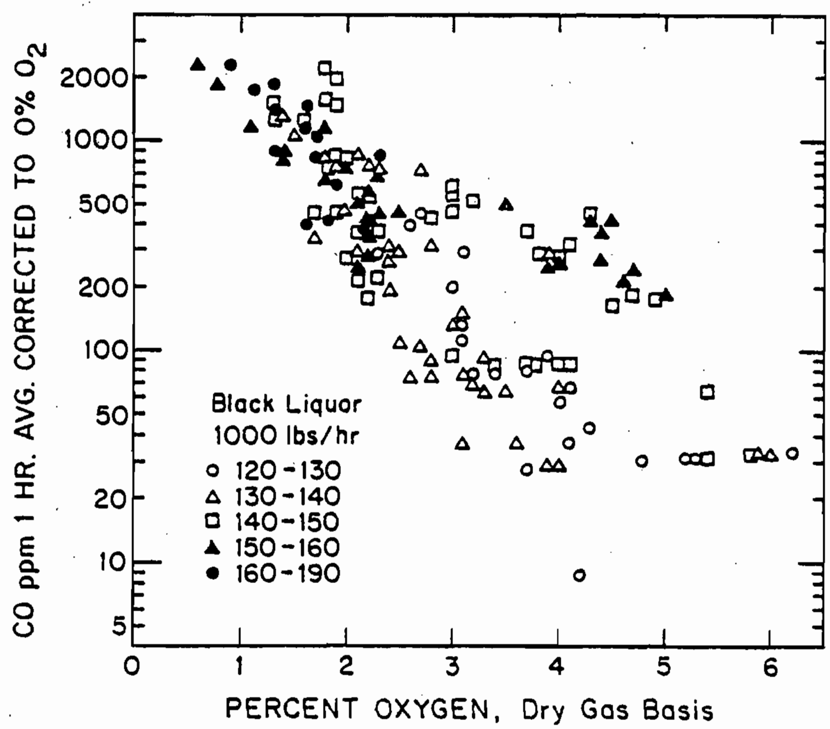

FIGURE 19

CARBON MONOXIDE EMISSIONS FROM KRAFT RECOVERY FURNACE D EXPRESSED AS ppm CORRECTED TO 0 PERCENT O_2 AS A FUNCTION OF STACK GAS OXYGEN CONCENTRATION

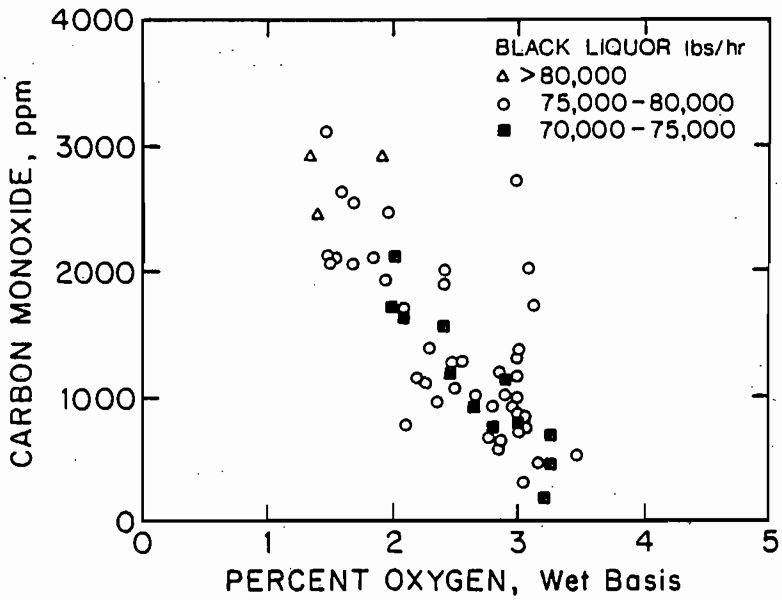

FIGURE 20

CARBON MONOXIDE EMISSIONS FROM KRAFT RECOVERY FURNACE E EXPRESSED AS ppm CORRECTED TO 0 PERCENT O_2 AS A FUNCTION OF STACK GAS OXYGEN CONCENTRATION

D. Relationship Between Carbon Monoxide and TRS Emissions from Kraft Recovery Furnaces

Total Reduced Sulfur (TRS) emission data was collected from the recovery furnaces along with the carbon monoxide emission data to look for possible correlation between the two. Both TRS emissions and carbon monoxide emissions for the two DCE equipped recovery furnaces, A and C were low and no relationship could be found. Recognizing the TRS-CO emission relationships on DCE furnaces are tenous because of TRS contributions of the DCE, TRS emissions from this type of kraft recovery furnace tended to increase when carbon monoxide emissions increased above some level. This is illustrated in Figures 21 to 23 where the percent of time the TRS concentration in the exit gas exceeded 5 ppm was plotted as a function of the carbon monoxide concentration for DCE furnaces. These diagrams show that the probability of exceeding a 5 ppm TRS concentration increased with higher carbon monoxide emission levels. If appears unlikely that the increase in TRS emissions, as carbon monoxide increased, would be attributable to the TRS contribution from the contact evaporator. The TRS-carbon monoxide relationship for each DCE recovery furnace was found to be different. In only one case, however, were TRS emissions sufficiently low (Recovery Furnace C) to indicate a critical level of carbon monoxide where TRS emissions started to ncasi special report

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ESTIMATES OF 1990 SULFUR DIOXIDE AND OXIDES OF NITROGEN EMISSIONS FROM PULP AND PAPER MILLS

SPECIAL REPORT 93 - 03

FEBRUARY 1993

E. Lime Kilns

Lime kiln SO_2 and NO_x emissions were calculated based on reported 1990 equivalent pulp production (or lime production) and an emission factor of 0.06 lb/ADTP for SO_2 and 0.6 lb/ADTP for NO_x (6), unless monitoring or emissions test data were available. As noted in reference 6, average emissions do not appear to depend on the type of fossil fuel burned or whether non-condensible gases (NCGs) are combusted in the kiln.

F. TRS Incineration

SO_2 emissions from the burning of NCGs in a stand-alone incinerator were calculated from reported (a) measured SO_2 emissions in lb/ADTP, (b) kraft pulp production, and (c) hours of operation of the incinerator for 1990. If measurements were not reported, an average emission factor of 8 lb SO_2/ADTP was used. If a scrubber SO_2 removal efficiency was reported, SO_2 emissions were reduced accordingly. NO_x emissions were assumed to be insignificant.

If NCGs were reported as being burned in a boiler, a factor of 8 lb SO_2/ADTP and total kraft pulp production were used to estimate the additional uncontrolled emissions. If the boiler was equipped with an SO_2 removal system, emissions were reduced by the reported average 1990 removal efficiency. If the boiler was only used as a back-up combustion device, it was assumed that NCGs were routed to the boiler 2% of the time.

G. Sulfite Mills

Most sulfite mills reported annual SO_2 emissions from the pulp mill and any chemical recovery operations based on measurements or monitoring results. If a mill did not report any measurements or monitoring information, the average emission factor for the reporting mills (10.7 lb SO_2/ADTP) and the reported 1990 pulp production were used to estimate SO_2 emissions.

Similarly, NO_x emissions were based on reported monitoring or measurement data. In the absence of data, an emission factor for ammonia-based mills with recovery furnaces of 9.2 lb/ADTP and for magnesium-based mills with recovery furnaces of 2.1 lb/ADTP and reported annual pulp production were used to estimate NO_x emissions.

H. Stand-Alone Semi-Chemical Mills

Very little data are available for these mills. SO_2 emissions from pulping and liquor burning operations at sulfur-based semi-chemical mills were computed with an emission factor

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COMPILATION OF 'AIR TOXIC' EMISSION DATA FOR BOILERS, PULP MILLS, AND BLEACH PLANTS

TECHNICAL BULLETIN NO. 650

JUNE 1993

B. Oil-Fired Boilers

Table 4A provides uncontrolled emission factors for oil combustion for eleven trace metals, POM and formaldehyde for both residual and distillate grade oil firing. These factors are reproduced from Table 4.3.3-3B of the current draft update to the AP-42 document on fuel oil combustion (2). Just as for coal, sulfuric acid emissions from oil combustion are related to the oil sulfur content, and these are not shown here.

The emissions of trace metals from oil-fired boilers would be affected by the control device that follows the boiler (except perhaps Hg and Se which remain mostly in the vapor phase). However, no data on control removal efficiencies of the various metals are available at the present time. Removal efficiencies of POM, HCHO, Se and Hg may be assumed to be zero for reasons given earlier for coal combustion.

Table 4B provides emission data for 11 trace metals, benzene, formaldehyde, total polycyclic aromatic hydrocarbons (PAHs), and several PAH species for residual fuel oil combustion. These data were obtained from stack tests conducted on several utility boilers during the California Utility Boiler Study (5). Speciated PAH emissions data for industrial boilers are unavailable at the present time. It should be noted for the data in Table 4B, the percentage of samples that was below the method detection limit was quite high for a number of compounds. In particular, all tests for benzene gave non-detectable concentrations. The rules for treatment of non-detected data in this report, which were outlined in section III, may be used here. Fuel metal analyses were also carried out during the Utility Boiler Study (5). Based on the study results, the authors cautioned that prediction of metal emissions from fuel analyses may significantly over- or underestimate actual emissions (5).

C. Gas-Fired Boilers

Table 4C provides emission data for benzene, formaldehyde, total PAHs and speciated PAHs corresponding to natural gas combustion in utility boiler stacks (5). Non-criteria pollutant emission data corresponding to industrial boilers were not available in the latest update to section to 1.4 of the AP-42 document (3). Once again, concentrations of several compounds as shown in Table 4C were below their method detection limits and tests for benzene always yielded non-detectable concentrations.

D. Wood-Fired Boilers

Table 5A lists organic compound emissions data corresponding to 20 wood-fired boilers. Based on available information, only wood residue was fired in these boilers during the tests. Emissions from four boilers in which wastewater treatment sludge was also fired in separate tests are described in the next section. The units described in Table 5A range in size from 6000 lb steam/hr to about 650,000 lb steam/hr, and include fuel cells, Dutch ovens, stokers and fluidized beds. Boilers with mill codes WFB16a, WFB17, WFB18a, WFB19a and WFB20a correspond to wood-fired boilers situated at kraft pulp mills, while the remaining 15 boilers (all in California) correspond to relatively smaller steam or electric power generating facilities burning bark, sawdust and wood shavings (6,7).

A total of 49 different organic compounds, several of which are not on the 1990 CAAA list of 189 HAPs, are listed in Table 5A. Test methods used are identified in the table when such information was available. The emissions are expressed in both concentration units (ppb or ppm @ 12 percent CO_2) and in units of lb/10^6 Btu (lb/MM Btu). For conversion to units of lb/ton of dry wood residue, a nominal conversion factor of 18 x 10^6 Btu/ton dry wood residue may be used. Concentrations below detection limits are treated as described in section III.

Small amounts of organic compounds are emitted from virtually all combustion sources. As with CO emissions, the rate at which these products of incomplete combustion (PICs) are emitted depends on the combustion efficiency of the boiler. The burning of auxiliary fossil fuel such as natural gas or fuel oil along with wood residue is expected to enhance the combustion efficiency in the boiler, resulting in reduced emissions of PICs. The species of wood residue fired, viz., softwood versus hardwood, is also expected to impact the level of some organic emissions. Formaldehyde emissions, for example, are expected to be higher when firing hardwood residues as opposed to softwood residues. For boilers equipped with a scrubber, an additional factor that may affect the level of organic emissions is the type of scrubbing medium used. The use of fresh water versus pulp mill condensates in the scrubber would be expected to minimize stripping of organic constituents from the scrubbing medium. Finally, the type of control device may also affect the level of emissions of some PICs. For example, water soluble PICs such as methanol would be expected to be partially absorbed across a wet scrubber. Also, semi-volatile PICs that exist partially in the condensed phase in the flue gases are perhaps more efficiently precipitated across ESPs as compared to scrubbers or mechanical control devices such as multiclones.

Table 5B provides trace metal emissions data for 17 wood-fired boilers. It should be noted that the particulate control devices on these boilers varied widely. Boilers with mill codes WA, WN1 and WO1 correspond to wood-fired boilers situated at kraft pulp mills, while boilers with mill codes WB to WL (all in California) correspond to relatively smaller steam or electric power generating facilities burning bark, sawdust and wood shavings (6).

Table 5B includes data for a total of eighteen different trace metals, including hexavalent chromium. Test methods used are identified in the table when such information was available. Emissions are expressed both in units of $lb/10^{12}$ Btu and lb/ton of dry fuel (lb/TDF). Concentrations below detection limits are treated as described in section III.

Emissions from the four boilers equipped with electrostatic precipitators are shown separately from the remaining 13 boilers. Several trace metals selectively adsorb onto the fly ash surface, and thus their removal is dependent on particulate control device efficiencies, especially for submicron-sized particulates. Also, the type of wood residue burned can vary considerably from one mill to another. Residues with higher trace metal contents will naturally have a greater propensity to emit higher concentrations of these trace metals. Trace metal content in the fuel and the control device efficiencies for individual trace metals are key factors in determining trace metal emissions from wood-fired boilers.

E. Wastewater Treatment Sludge Burning in Wood-Fired Boilers

Table 5C provides organic compound emissions data for four boilers which were tested while firing wood residue and also while firing a combination of small quantities (<12 percent heat input) of wastewater treatment sludge and wood residue. All four boilers were situated at pulp mills that produced bleached pulp. In the case of the mill WFB16 boiler, which is equipped with a wet scrubber, these tests were repeated, once using fresh water and once using pulp mill clean condensates as the scrubbing fluid.

Data on emissions of 48 organic compounds when burning wood residue and wood residue in combination with kraft bleached mill sludge in the four wood-fired boilers are provided in Table 5C. A comparison of the emission data for the two fuel types shows no discernible impact on emissions of these organics when the sludge was co-fired with wood residue. Also, although data are restricted to just one boiler, except for emissions of methanol, the impact of using clean pulp mill condensates versus fresh water appears to be minimal.

Table 5D presents the results of tests for metals emissions from two boilers in which wood-waste and a combination of wood-waste and bleach kraft mill sludge were burned. The heat input from sludge during these tests was less than 12 percent. The first boiler was equipped with a scrubber, whereas the second boiler uses an electrostatic precipitator for particulate control. An examination of the results in Table 5D suggests that adding sludge to the wood-waste did not have any discernible impact on trace metals emissions from these boilers.

TABLE 3 EMISSION FACTORS FOR UNCONTROLLED BITUMINOUS COAL-FIRED BOILER COMBUSTION[a] (1)
(All Emission Factors in $lb/10^{12}$ Btu heat input)

Firing Configuration (SCC)	Sb	As	Be	Cd	Cr	Co	Pb	Mn	Hg	Ni	Se	POM	HCOH
Pulverized Coal Configuration Unknown (no SCC)	no data	no data	no data	no data	1922	no data	no data	no data	no data	no data	no data	no data	112 b
Pulverized Coal Wet Bottom (10100201)	no data	538	81	44-70	1020-1570	no data	507 c	808-2980	16	840-1290	no data	no data	no data
Pulverized Coal Dry Bottom (10100202)	no data	684	61	44.4	1250-1570	no data	507 c	228-2980	16	1030-1290	no data	2.08	no data
Pulverized coal Dry Bottom, Tangential (10100212)	no data	no data	no data	no data	no data	no data	no data	no data	no data	no data	no data	2.4	no data
Cyclone Furnace (10100203)	no data	115	<81	28	212-1502	no data	507 c	228-1300	16	174-1290	no data	no data	no data
Stoker Configuration Unknown (no SCC)	no data	no data	73	no data	19-300	no data	no data	2170	16	775-1290	no data	no data	no data
Spreader Stoker (10100204)	no data	264-542	no data	21-43	942-1570	no data	507 c	no data	no data	no data	no data	no data	221 d
Traveling Grate, Overfed Stoker (10100205)	no data	542-1030	no data	43-82	no data	no data	507 c	no data	no data	no data	no data	no data	140 e

[a] The emission factors in this table are the ranges of factors evaluated in the literature search. If only one data point was found, it was still reported in this table.
[b] Based on 2 units; 1640 GJ/hr, 140 GJ/hr
[c] Lead emission factors were taken directly from an EPA background document for support of the NAAQS.
[d] Based on 1 unit; 62 GJ/hr
[e] Based on 1 unit; 155 GJ/hr

TABLE 4A EMISSION FACTORS FOR EXTERNAL RESIDUAL AND DISTILLATE OIL COMBUSTION[a] (2)
(All Emission Factors in lb/10^{12} Btu heat input)

Firing Configuration (SCC)	Sb	As	Be	Cd	Cr	Co	Pb	Mn	Hg	Ni	Se	POM	HCOH b
Residual, Grade 6, Normal Firing (10100401)	24-46	19-114	4.2-4.4	16-211	21-128	77-121	28-194	23-74	1.4-32	837-2333	37-39	7.4-8.4c	161-405
Residual, Grade 6, Normal Firing (10100404)	24-46	19-114	4.2-4.4	16-211	21-128	77-121	28-194	23-74	1.4-32	837-2333	37-39	7.4-8.4c	161-405
Residual, Grade 6, Normal Firing (10200401)	24-46	19-114	4.2-4.4	16-211	21-128	77-121	28-194	23-74	1.4-32	837-2333	37-39	7.4-8.4c	161-405
Residual, Grade 6, Normal Firing (10300401)	24-46	19-114	4.2-4.4	16-211	21-128	77-121	28-194	23-74	1.4-32	837-2333	37-39	7.4-8.4c	161-405
Distillate, Grade 2, (10100501)	no data	4.2	2.5	11	48-67	no data	8.9	14	3.0	170	no data	22d	233-405
Distillate, Grade 2, (10200501)	no data	4.2	2.5	11	48-67	no data	8.9	14	3.0	170	no data	22d	233-405
Distillate, Grade 2, (10300501)	no data	4.2	2.5	11	48-67	no data	8.9	14	3.0	170	no data	22d	233-405

a The emission factors in this table are the ranges of factors evaluated in the literature search. If only one data point was found, it was still reported in this table.
b Based on old and limited data
c Particulate and gaseous POM
d Particulate POM only

TABLE 4B EMISSION DATA FOR UTILITY BOILERS FIRING RESIDUAL FUEL OIL (5)

	lb/MMBtu (Range)	% of Samples Below Detection Limit
Benzene	$2.27 \times 10^{-6} - 3.00 \times 10^{-6}$	100
Formaldehyde	$1.10 \times 10^{-5} - 1.65 \times 10^{-4}$	47
Arsenic	$3.97 \times 10^{-6} - 2.00 \times 10^{-5}$	0
Beryllium	$4.21 \times 10^{-8} - 2.10 \times 10^{-7}$	39
Cadmium	$6.72 \times 10^{-7} - 3.04 \times 10^{-5}$	0
Chromium VI	$4.07 \times 10^{-7} - 4.04 \times 10^{-6}$	7
Copper	$9.76 \times 10^{-6} - 1.65 \times 10^{-5}$	0
Lead	$2.51 \times 10^{-6} - 2.20 \times 10^{-5}$	0
Manganese	$3.90 \times 10^{-6} - 2.60 \times 10^{-5}$	0
Mercury	$2.00 \times 10^{-6} - 6.15 \times 10^{-5}$	100
Nickel	$3.00 \times 10^{-4} - 1.06 \times 10^{-3}$	0
Selenium	$3.40 \times 10^{-6} - 1.14 \times 10^{-5}$	22
Zinc	$7.01 \times 10^{-5} - 4.50 \times 10^{-4}$	0
Total PAH*	$5.31 \times 10^{-7} - 5.29 \times 10^{-5}$	64
Acenapthene	$6.32 \times 10^{-9} - 1.02 \times 10^{-7}$	33
Acenaphthylene	$6.32 \times 10^{-9} - 9.22 \times 10^{-9}$	100
Anthracene	$6.32 \times 10^{-9} - 1.43 \times 10^{-8}$	39
Benz[a]anthracene	$6.40 \times 10^{-10} - 1.02 \times 10^{-7}$	83
Benzo[b]fluoranthene	$6.40 \times 10^{-9} - 3.65 \times 10^{-8}$	89
Benzo[k]fluoranthene	$6.40 \times 10^{-9} - 3.65 \times 10^{-8}$	89
Benzo[a]pyrene	$6.32 \times 10^{-9} - 9.22 \times 10^{-9}$	100
Benzo[g,h,i]perylene	$6.40 \times 10^{-9} - 6.95 \times 10^{-8}$	94
Chrysene	$6.40 \times 10^{-9} - 1.75 \times 10^{-8}$	83
Dibenzo[a,h]anthracene	$6.40 \times 10^{-9} - 2.47 \times 10^{-8}$	83
Fluroanthene	$6.40 \times 10^{-9} - 2.55 \times 10^{-8}$	39
Fluorene	$6.40 \times 10^{-9} - 3.15 \times 10^{-8}$	39
Indeno[1,2,3,c,d]pyrene	$6.40 \times 10^{-9} - 6.25 \times 10^{-8}$	83
Napthalene(1)	$4.23 \times 10^{-7} - 1.21 \times 10^{-5}$	0
Phenanthrene	$6.40 \times 10^{-9} - 1.08 \times 10^{-7}$	22
Pyrene	$6.40 \times 10^{-9} - 3.17 \times 10^{-8}$	50

*PAH - Polycyclic Aromatic Hydrocarbons

(1) It should be noted that napthalene is a decomposition product of XAD-2 resin. Although resin modules are stored in ice chests to minimize decomposition, it is still common to see measurable napthalene levels in both PAH samples and in blank samples. It is possible that much of the reported napthalene emissions (after correction for field blank values) are due to resin decomposition and not to unit emissions. CARB is currently evaluating this problem and may remove napthalene from the test method.

TABLE 4C EMISSION DATA FOR UTILITY BOILERS FIRING NATURAL GAS (5)

	lb/MMBtu (Range)	% of Samples Below Detection Limit
Benzene	1.08×10^{-6} - 4.48×10^{-6}	100
Formaldehyde	1.70×10^{-5} - 3.33×10^{-4}	13
Total PAH (1)(2)	4.48×10^{-8}	90
Napthalene(3)	1.99×10^{-8}	0
Acenaphthylene	1.41×10^{-9}	100
Acenaphthene	1.41×10^{-9}	100
Fluorene	2.01×10^{-9}	67
Phenanthrene	3.70×10^{-9}	67
Anthracene	1.57×10^{-9}	100
Fluoranthene	1.41×10^{-9}	100
Pyrene	1.41×10^{-9}	100
Benz[a]anthracene	1.41×10^{-9}	100
Chrysene	1.41×10^{-9}	100
Benzo[b]fluoranthene	1.59×10^{-9}	100
Benzo[k]fluoranthene	1.49×10^{-9}	100
Benzo[a]pyrene	1.65×10^{-9}	100
Indeno[1,2,3,c,d]pyrene	1.49×10^{-9}	100
Dibenzo[a,h]anthracene	1.41×10^{-9}	100
Benzo[g,h,i]perylene	1.53×10^{-9}	100

(1) PAH - Polycyclic Aromatic Hydrocarbons
(2) No range of values is given. This data was obtained from a single-triplicate test series on a 750 MWe, opposed fired boiler (natural gas).
(3) Refer to Note #1, Table 4B

TABLE 5B SUMMARY OF 'AIR TOXIC' TRACE METAL EMISSIONS FROM WOOD-FIRED BOILERS

MILL CODE	FUEL	TEST DATE	SOURCE DESCRIPTION	CONTROL DEVICE	REFERENCE
WA	WD RES	1991	STOKER, 350 KPPH	SCRUBBER	14
WB	WD RES	1990	FUEL CELL, 6 KPPH	CYCLONE	6
WC	WD RES	1990	FUEL CELL, 68 KPPH	MULTICLONE	6
WD	WD RES	1990	DUTCH OVEN, 50 KPPH	MULTICLONE	6
WE	WD RES	1990	DUTCH OVEN, 37 KPPH	WET SCRUBBER	6
WF	WD RES	1990	STOKER, 90 KPPH	WET SCRUBBER	6
WG	WD RES	1990	STOKER, 118 KPPH	WET SCRUBBER	6
WK	WD RES	1990	AIR INJECTED, 43 KPPH	MULTICLONE	6
EPA1	WD RES	NA	NA	NA	20
EPA2	WD RES	NA	NA	NA	20
EPA3	WD RES	NA	NA	NA	20
WN1	WD RES	1992	SPREADER STOKER, 200 KPPH	SCRUBBER	8
WO1	WD RES	1990	SPREADER STOKER, 500 to 550 KPPH	ELECTROSCRUBBER	14
WH	WD RES	1990	STOKER, 136 KPPH	ELECTROSTATIC PRECIPITATOR	6
WI	WD RES	1990	STOKER, 164 KPPH	ELECTROSTATIC PRECIPITATOR	6
WJ	WD RES	1990	STOKER, 167 KPPH	ELECTROSTATIC PRECIPITATOR	6
WL	WD RES	1990	FLUIDIZED BED, 92 KPPH	ELECTROSTATIC PRECIPITATOR	6

References

6. Sassenrath, C.P., "Air Toxic Emissions from Wood-Fired Boilers'" 1991 Tappi Environmental Conference Proceedings, San Antonio, pp 483-491.

8. Texas Emissions Speciation Study, Emission Test Results, Roy F. Weston, Inc. January 1993.

14. Individual Mill Testing for 'Air Toxics', NCASI Mill File Information.

20. "Toxic Air Pollutant Emission Factors – A Compilation of Selected Air Toxic Compounds and Sources, Second Edition, EPA-450-2-90-011, October 1990.

TABLE 5B SUMMARY OF 'AIR TOXIC' TRACE METAL EMISSIONS FROM WOOD–FIRED BOILERS, CONTD.

	Antimony, Sb		Arsenic, As		Barium, Ba		Beryllium, Be		Cadmium, Cd		Cobalt, Co	
MILL	lb/	lb/	lb/	lb/	lb/	lb/	lb/	lb/	lb/	lb/	lb/	lb/
CODE	1E+12 Btu	TDF*	1E+12 Btu	TDF	1E+12 Btu	TDF	1E+12 Btu	TDF	1E+12 Btu	TDF	1E+12 Btu	TDF

BOILERS WITHOUT ESPs

WA					6.7E+00	1.2E−04			4.7E−01	8.5E−06		
WB			1.4E+01	2.5E−04			ND**	ND**	1.7E+00	3.1E−05		
WC			6.6E−01	1.2E−05			ND**	ND**	3.7E+00	6.7E−05		
WD			2.0E+01	3.6E−04			ND**	ND**	5.5E+00	9.8E−05		
WE			6.3E+00	1.1E−04			ND**	ND**	1.7E+00	3.0E−05		
WF			6.6E+00	1.2E−04			ND**	ND**	1.0E+00	1.9E−05		
WG			3.7E+01	6.7E−04			ND**	ND**	5.3E−01	9.5E−06		
WK			8.8E−01	1.6E−05			ND**	ND**	1.8E+00	3.2E−05		
EPA1					2.6E+02	4.6E−03					1.1E+01	2.0E−04
EPA2					3.9E+02	7.0E−03					9.8E−01	1.8E−05
EPA3					4.1E+02	7.4E−03						
WN1			ND[3.7]	ND[6.5E−5	ND[2950]	ND[5.2E−2	ND[3.7]	ND[6.5E−5	ND[3.7]	ND[6.5E−5]		
WO1	ND[140]	ND[2.5E−3	1.4E+00	2.5E−05	4.8E+03	8.7E−02	1.4E+02	2.5E−03			4.2E+02	7.6E−03
AVG	ND[140]	ND[2.5E−3	9.8E+00	1.8E−04	1.2E+03	2.2E−02	1.7E+01	3.1E−04	2.0E+00	3.7E−05	1.5E+02	2.6E−03
MAX			3.7E+01	6.7E−04	4.8E+03	8.7E−02	1.4E+02	2.5E−03	5.5E+00	9.8E−05	4.2E+02	7.6E−03
MIN			ND	ND	ND	ND	ND	ND	ND	ND	9.8E−01	1.8E−05
SOURCES	1		9		6		9		8		3	

BOILERS WITH ESPs

WH			2.1E−01	3.8E−06			ND**	ND**	3.0E−01	5.5E−06		
WI			4.1E−01	7.3E−06			ND**	ND**	8.4E−01	1.5E−05		
WJ			2.1E−01	3.8E−06			ND**	ND**	2.1E−01	3.8E−06		
WL			2.0E−01	3.6E−06			ND**	ND**	2.6E−01	4.6E−06		
AVG			2.6E−01	4.6E−06			0.0E+00	0.0E+00	4.0E−01	7.2E−06		
MAX			4.1E−01	7.3E−06			0.0E+00	0.0E+00	8.4E−01	1.5E−05		
MIN			2.0E−01	3.6E−06			0.0E+00	0.0E+00	2.1E−01	3.8E−06		
SOURCES			4				4		4			

TEST METHODS – (1) MILLS WB to WL – CARB 436 (CARB 425 for Cr & Cr+6); (2) MILLS WNI & WO1 – EPA DRAFT MULTIPLE METALS;

* TDF – ton of dry wood fuel

** detection limit unknown; assumed zero or lowest detection limit in column for purposes of estimating average

TABLE 5B SUMMARY OF 'AIR TOXIC' EMISSIONS (METALS) FROM WOOD-FIRED BOILERS, CONTD.

	Chromium, Cr		Chromium +6		Copper, Cu		Lead, Pb		Manganese, Mn		Mercury, Hg	
MILL	lb/	lb/	lb/	lb/	lb/	lb/	lb/	lb/	lb/	lb/	lb/	lb/
CODE	1E+12 Btu	TDF	1E+12 Btu	TDF	1E+12 Btu	TDF	1E+12 Btu	TDF	1E+12 Btu	TDF	1E+12 Btu	TDF
BOILERS WITHOUT ESPs												
WA	6.6E-01	1.2E-05			1.7E+00	3.1E-05	1.4E+00	2.6E-05	1.1E+01	2.0E-04	6.8E-01	1.2E-05
WB	3.1E+01	5.6E-04	1.6E+02	2.9E-03	1.2E+02	2.1E-03	3.2E+02	5.8E-03	1.1E+03	2.0E-02	0.0E+00	0.0E+00
WC	4.4E+00	7.8E-05	3.3E+00	5.9E-05	3.4E+01	6.1E-04	3.2E+00	5.7E-05	1.6E+03	2.9E-02	2.9E-01	5.2E-06
WD	9.6E+00	1.7E-04	4.8E+00	8.6E-05	1.8E+02	3.2E-03	7.8E+01	1.4E-03	5.3E+03	9.5E-02	2.3E+00	4.2E-05
WE	3.1E+00	5.6E-05	5.3E+00	9.5E-05	3.3E+01	6.0E-04	6.9E+01	1.2E-03	3.8E+02	6.8E-03	0.0E+00	0.0E+00
WF	1.5E+01	2.7E-04	2.0E+00	3.6E-05	1.5E+01	2.6E-04	3.6E+01	6.5E-04	1.0E+02	1.8E-03	4.8E-01	8.7E-06
WG	4.9E+00	8.8E-05	5.0E+00	8.9E-05	3.7E+01	6.6E-04	2.0E+01	3.6E-04	1.3E+02	2.4E-03	8.7E-01	1.6E-05
WK	5.5E+00	9.9E-05	6.4E+00	1.1E-04	2.9E+01	5.3E-04	1.4E+01	2.5E-04	1.4E+03	2.6E-02	0.0E+00	0.0E+00
EPA1	2.1E+01	3.8E-04			4.4E+01	7.9E-04						
EPA2	1.7E+01	3.0E-04			2.2E+01	4.0E-04						
EPA3	1.7E+01	3.0E-04			5.6E+01	1.0E-03						
WN1	6.6E+00	1.2E-04	ND[0.47]	ND[8.3E-6	1.1E+01	1.9E-04	1.2E+01	2.2E-04	2.9E+01	5.1E-04	ND[3.7]	ND[6.6E-5
WO1	1.4E+02	2.5E-03			4.2E+02	7.6E-03	1.4E+02	2.5E-03	1.0E+04	1.9E-01	3.6E+01	6.6E-04
AVG	2.1E+01	3.8E-04	2.3E+01	4.2E-04	7.7E+01	1.4E-03	6.9E+01	1.2E-03	2.0E+03	3.7E-02	4.3E+00	7.7E-05
MAX	1.4E+02	2.5E-03	1.6E+02	2.9E-03	4.2E+02	7.6E-03	3.2E+02	5.8E-03	1.0E+04	1.9E-01	3.6E+01	6.6E-04
MIN	6.6E-01	1.2E-05	0.0E+00	0.0E+00	1.7E+00	3.1E-05	1.4E+00	2.6E-05	1.1E+01	2.0E-04	0.0E+00	0.0E+00
SOURCES	13		8		13		10		10		10	
BOILERS WITH ESPs												
WH	1.3E+00	2.3E-05	3.4E+00	6.1E-05	3.1E+00	5.6E-05	1.6E+00	2.8E-05	9.5E+01	1.7E-03	0.0E+00	0.0E+00
WI	9.1E-01	1.6E-05	1.7E+00	3.0E-05	4.1E+00	7.4E-05	2.7E+00	4.9E-05	5.6E+01	1.0E-03	3.9E-01	6.9E-06
WJ	4.2E-01	7.6E-06	1.0E+00	1.9E-05	1.6E+00	2.9E-05	1.7E+00	3.1E-05	2.3E+01	4.2E-04	2.9E-01	5.2E-06
WL	1.5E+00	2.7E-05	2.3E+00	4.1E-05	4.8E+00	8.7E-05	2.3E+00	4.1E-05	6.5E+01	1.2E-03	0.0E+00	0.0E+00
AVG	1.0E+00	1.8E-05	2.1E+00	3.8E-05	3.4E+00	6.1E-05	2.1E+00	3.7E-05	6.0E+01	1.1E-03	1.7E-01	3.0E-06
MAX	1.5E+00	2.7E-05	3.4E+00	6.1E-05	4.8E+00	8.7E-05	2.7E+00	4.9E-05	9.5E+01	1.7E-03	3.9E-01	6.9E-06
MIN	4.2E-01	7.6E-06	1.0E+00	1.9E-05	1.6E+00	2.9E-05	1.6E+00	2.8E-05	2.3E+01	4.2E-04	0.0E+00	0.0E+00
SOURCES	4		4		4		4		4		4	

TABLE 5B SUMMARY OF 'AIR TOXIC' EMISSIONS (METALS) FROM WOOD-FIRED BOILERS, CONTD.

	Nickel, Ni		Phosphorus, P		Selenium, Se		Silver, Ag		Thallium, Th		Zinc, Zn	
MILL	lb/	lb/	lb/	lb/	lb/	lb/	lb/	lb/	lb/	lb/	lb/	lb/
CODE	1E+12 Btu	TDF	1E+12 Btu	TDF	1E+12 Btu	TDF	1E+12 Btu	TDF	1E+12 Btu	TDF	1E+12 Btu	TDF
BOILERS WITHOUT ESPs												
WA							1.2E−01	2.2E−06			7.8E+01	1.4E−03
WB	8.6E+00	1.5E−04			0.0E+00	0.0E+00					3.1E+02	5.6E−03
WC	8.2E+00	1.5E−04			0.0E+00	0.0E+00					2.7E+02	4.9E−03
WD	2.3E+01	4.1E−04			0.0E+00	0.0E+00					9.8E+02	1.8E−02
WE	2.6E+01	4.6E−04			0.0E+00	0.0E+00					7.6E+02	1.4E−02
WF	3.7E+00	6.7E−05			0.0E+00	0.0E+00					2.6E+02	4.6E−03
WG	3.6E+00	6.5E−05			0.0E+00	0.0E+00					4.1E+02	7.4E−03
WK	8.4E+00	1.5E−04			0.0E+00	0.0E+00					3.1E+02	5.7E−03
EPA1	2.6E+02	4.6E−03					2.6E+00	4.6E−05				
EPA2	3.5E+02	5.2E−03					2.3E+03	3.4E−02				
EPA3	5.6E+02	6.4E−03					2.8E+01	3.2E−04				
WN1	ND [3.7]	ND [6.6E−5	1.6E+02	2.9E−03	ND [3.7]	ND [6.6E−5	ND [3.7]	ND [6.6E−5	ND [3.7]	ND [6.6E−5]		
WO1	1.4E+02	2.5E−03			5.6E+00	1.0E−04	1.4E+02	2.5E−03			7.8E+03	1.4E−01
AVG	1.2E+02	1.7E−03	1.6E+02	2.9E−03	8.3E−01	1.5E−05	4.1E+02	6.2E−03	ND [3.7]	ND [6.6E−5	1.2E+03	2.2E−02
MAX	5.6E+02	6.4E−03	1.6E+02	2.9E−03	5.6E+00	1.0E−04	2.3E+03	3.4E−02			7.8E+03	1.4E−01
MIN	0.0E+00	0.0E+00	1.6E+02	2.9E−03	0.0E+00	0.0E+00	0.0E+00	0.0E+00			7.8E+01	1.4E−03
SOURCES	12		1		9		6		1		9	
BOILERS WITH ESPs												
WH	2.7E+00	4.8E−05			0.0E+00	0.0E+00					4.6E+01	8.2E−04
WI	6.3E+00	1.1E−04			0.0E+00	0.0E+00					4.5E+01	8.1E−04
WJ	1.7E+00	3.0E−05			0.0E+00	0.0E+00					1.1E+01	2.0E−04
WL	4.1E+00	7.4E−05			3.8E+00	6.8E−05					2.8E+01	5.1E−04
AVG	3.7E+00	6.6E−05			9.5E−01	1.7E−05					3.3E+01	5.9E−04
MAX	6.3E+00	1.1E−04			3.8E+00	6.8E−05					4.6E+01	8.2E−04
MIN	1.7E+00	3.0E−05			0.0E+00	0.0E+00					1.1E+01	2.0E−04
SOURCES	4				4						4	4

ncasi technical bulletin

NATIONAL COUNCIL OF THE PAPER INDUSTRY FOR AIR AND STREAM IMPROVEMENT, INC.
P.O. BOX 13318, RESEARCH TRIANGLE PARK, NC 277709-3318

COMPILATION OF 'AIR TOXIC' AND TOTAL HYDROCARBON EMISSION DATA FOR SOURCES AT CHEMICAL WOOD PULP MILLS

VOLUME 1

AND

VOLUME 2

TECHNICAL BULLETIN NO. 701

OCTOBER 1995

H. Sulfite Pulping Area Sources

Table 10 presents volatile organic compound emission data from sulfite pulping area sources. Emission sources for which data were available include two redstock washers, two nuisance scrubbers, one bleach plant, one combined digester evacuation vent and one combined blow pit vent. These data should be used with caution since only information from two mills was available. All the emission data for these two mills were obtained during the NCASI MACT study, and these have been described in detail in NCASI Technical Bulletin No. 682 (19). A total of 28 volatile organics were measured in the emissions of these sulfite pulping area sources. Total hydrocarbon emissions and emissions of terpenes were also measured. Methanol is, once again, the dominant VOC emitted.

VII CHEMICAL RECOVERY AREA SOURCES

A. Black Liquor Oxidation Systems

Table 11 presents volatile organic emissions data for 16 black liquor oxidation (BLOX) systems. All 16 systems oxidized strong black liquor. Most of the 16 systems use single stage oxidation. A total of 71 volatile organic compounds were identified in the emissions from these 16 BLOX systems, as well as H_2S and other reduced sulfur compounds such as CS_2 and COS. Emissions of total hydrocarbons from six BLO tank vents and terpenes from five tank vents are also shown in Table 11. The most dominant VOC emitted is methanol, with a median emission factor of 0.24 lb/TBLS (ton of BLS). Single source measurements should be used with caution.

VOC emissions from BLOX systems are most likely largely due to their presence in the black liquor itself. The level of gas-liquid agitation and the vent gas flow rate will also influence these emissions. Oxidation of dissolved lignin in the BLOX reactor is also expected to contribute, but to a lesser extent. Volatile organic compounds present in black liquor vary with the type of wood (hardwood or softwood) pulped, the geographic location of the wood species (north vs south) and the quality of the raw chemicals used in the kraft pulping process.

B. Kraft DCE Recovery Furnaces

Table 12A presents data for volatile organic compound emissions from 21 kraft recovery furnace stacks where each furnace had a direct-contact evaporator (DCE). Three of the stacks had multiple recovery furnaces venting through them. Each of these DCE recovery furnaces is equipped with a wet bottom precipitator (ESP). Two mills with DCE recovery furnaces have a wet scrubber following the precipitator.

Table 12A includes emissions data for 68 different volatile organic compounds. It also includes emissions data for HCl, reduced sulfur compounds, PAHs, H_2SO_4, terpenes and total

ncasi technical bulletin

NATIONAL COUNCIL OF THE PAPER INDUSTRY FOR AIR AND STREAM IMPROVEMENT, INC.
P.O. BOX 13318, RESEARCH TRIANGLE PARK, NC 27709-3318

COMPILATION OF 'AIR TOXIC' AND TOTAL HYDROCARBON EMISSIONS DATA FOR SOURCES AT CHEMICAL WOOD PULP MILLS

VOLUME 2

TABLE 11 SUMMARY OF 'AIR TOXIC' EMISSIONS FROM BLACK LIQUOR OXIDATION TANK VENTS

MILL CODE	TEST DATE	MILLION lb BLS/d	WOOD TYPE	LIQUOR TYPE	REFERENCE
BLOA	1991	2.5	SW	STRONG	8
BLOB	1991	2.7	SW	STRONG	8
BLOD	1990	2.9	HW/SW	STRONG	9
BLOE	1990	2.5	HW/SW	STRONG	9
BLOF	1992	4.1	HW/SW	STRONG	9
BLOH	1992	3.5	HW/SW	STRONG	9
BLOI	1992	1.9	SW	STRONG	3
BLOJ	1993	4.6	SW	STRONG	9
BLOK	1992	1.3	SW	STRONG	37
BLOMD	1994	1.7	HW/SW	STRONG	17
BLOMH	1994	2.1	SW	STRONG	17
BLOIC	1993	5.2	HW/SW	STRONG	9
BLOID	1993	3.9	HW/SW	STRONG	9
BLOIE	1993	2.5	HW/SW	STRONG	9
BLOIF	1993	2.6	HW/SW	STRONG	9
BLOIG	1993	4.7	HW/SW	STRONG	9

References

3. Texas Emissions Speciation Study, Emission Test Results, Roy F. Weston, Inc., January 1993.
8. Tests conducted by NCASI in 1991.
9. Individual Mill Testing for 'Air Toxics' - NCASI Mill File Information.
17. Volatile Organic Emissions from Pulp and Paper Mill Sources - Part VI - Kraft Recovery Furnaces and Black Liquor Oxidation Systems, NCASI Technical Bulletin No. 680, October 1994.
37. Emissions Testing of Combustion Processes in a Pulp and Paper Facility, Champion Intntl, Roanoke Rapids, NC, USEPA, EMB Report 92-KPM-27, Oct. 1992.

TABLE 11 SUMMARY OF 'AIR TOXIC' EMISSIONS FROM BLACK LIQUOR OXIDATION TANK VENTS, CONTD.

VOLATILE ORGANIC COMPOUND		MILL CODE	EMISSIONS RANGE lb/ton BLS	AVG lb/ton BLS	TEST METHOD	COMMENTS
ACETALDEHYDE		BLOF	0.143 to 0.168	1.5E-01	RTI DRAFT	
ACETALDEHYDE		BLOK	28.4 to 33.9 ppm	4.7E-02	M0011	
ACETALDEHYDE		BLOMD		2.2E-02	IMPINGER	NCASI METHOD
ACETALDEHYDE		BLOMH		6.0E-02	HEATED CANISTER	FID
ACETALDEHYDE		BLOIC	0.002 to 0.003	2.4E-03	IMPINGER	DNPH
ACETALDEHYDE		BLOID	0.016 to 0.017	1.6E-02	IMPINGER	DNPH
ACETALDEHYDE		BLOIE	0.021 to 0.104	6.6E-02	IMPINGER	DNPH
ACETALDEHYDE		BLOIF	0.017 to 0.023	2.1E-02	IMPINGER	DNPH
ACETALDEHYDE		BLOIG	0.006 to 0.033	2.1E-02	IMPINGER	DNPH
NO. OF TESTS	DETECTS		RANGE	MEDIAN		
9	9		2.0E-03 to 1.7E-01	2.2E-02		
ACETONE		BLOA	0.042 to 0.057	5.1E-02	IMPINGER	NCASI METHOD
ACETONE		BLOB	0.014 to 0.018	1.6E-02	IMPINGER	NCASI METHOD
ACETONE		BLOF	0.023 to 0.033	2.7E-02	RTI DRAFT	
ACETONE		BLOI	0.025 to 0.075	5.0E-03	M18	
ACETONE		BLOJ	0.012 to 0.017	1.5E-02	MOD NIOSH 2000	
ACETONE		BLOK	2.5 to 4.5 ppm	6.2E-03	VOST	1.5E-02 by M0011
ACETONE		BLOMD		4.3E-02	HEATED CANISTER	FID
ACETONE		BLOMH		3.1E-02	HEATED CANISTER	FID
ACETONE		BLOIC		ND[0.001]	IMPINGER	DNPH
ACETONE		BLOID	0.019 to 0.020	1.9E-02	HEATED CANISTER	FID
ACETONE		BLOIE	0.063 to 0.097	8.2E-02	HEATED CANISTER	FID
ACETONE		BLOIF	0.005 to 0.010	8.0E-03	IMPINGER	DNPH
ACETONE		BLOIG	0.003 to 0.016	8.6E-03	IMPINGER	DNPH
NO. OF TESTS	DETECTS		RANGE	MEDIAN		
13	12		ND to 0.097	1.6E-02		
ACETOPHENONE		BLOF		ND[1.1E-3]	RTI DRAFT	
ACETOPHENONE		BLOK	86 to 174 ppb	5.5E-04	SEMI-VOST	
ACETOPHENONE		BLOIC		ND[1.8E-4]	IMPINGER	DNPH
ACETOPHENONE		BLOID		ND[3.5E-3]	HEATED CANISTER	FID, [0.00015] by DNPH
ACETOPHENONE		BLOIE	ND to 7.0E-04	4.5E-04	IMPINGER	DNPH
ACETOPHENONE		BLOIF		ND[1.3E-2]	HEATED CANISTER	FID, [0.00039] by DNPH
ACETOPHENONE		BLOIG		ND[1.1E-2]	HEATED CANISTER	FID, [0.00023] by DNPH
NO. OF TESTS	DETECTS		RANGE	MEDIAN**		
7	2		ND to 5.5E-04	8.6E-05		
ACROLEIN		BLOF		ND[1.1E-3]	RTI DRAFT	
ACROLEIN		BLOK	13.3 to 20.6 ppb	3.1E-05	M0011	
ACROLEIN		BLOMH		ND[5.8E-5]	HEATED CANISTER	FID
ACROLEIN		BLOIC		ND[8.3E-5]	IMPINGER	DNPH
ACROLEIN		BLOID		ND[1.7E-3]	HEATED CANISTER	FID, ND[7.3E-05] by DNPH
ACROLEIN		BLOIE		ND[3.1E-4]	IMPINGER	DNPH
ACROLEIN		BLOIG		ND[1.3E-4]	IMPINGER	DNPH
NO. OF TESTS	DETECTS		RANGE	MEDIAN**		
7	1		ND to 3.1E-05	1.6E-06		
ANILINE		BLOK		ND	SEMI-VOST	
BENZALDEHYDE		BLOF	0.002 to 0.004	3.2E-03	RTI DRAFT	
BENZALDEHYDE		BLOK	732 to 843 ppb	2.8E-03	M0011	
BENZALDEHYDE		BLOIC		ND[1.6E-4]	IMPINGER	DNPH
BENZALDEHYDE		BLOID	ND to 1.7E-4	1.0E-04	IMPINGER	DNPH
BENZALDEHYDE		BLOIE	ND to 4.4E-3	2.6E-03	IMPINGER	DNPH
BENZALDEHYDE		BLOIF	3.4E-4 to 7.1E-4	5.2E-04	IMPINGER	DNPH
BENZALDEHYDE		BLOIG	ND to 4.6E-4	2.1E-04	IMPINGER	DNPH
NO. OF TESTS	DETECTS		RANGE	MEDIAN		
7	6		ND to 4.4E-03	5.2E-04		

TABLE 11 SUMMARY OF 'AIR TOXIC' EMISSIONS FROM BLACK LIQUOR OXIDATION TANK VENTS, CONTD.

VOLATILE ORGANIC COMPOUND		MILL CODE	EMISSIONS RANGE lb/ton BLS	AVG lb/ton BLS	TEST METHOD	COMMENTS
BENZENE		BLOF		ND[1.2E-03]	M18	
BENZENE		BLOI	16 ppb	1.9E-05	VOST	
BENZENE		BLOK	2.3 to 6.2 ppb	1.0E-05	VOST	
BENZENE		BLOMD		4.2E-04	HEATED CANISTER	FID
BENZENE		BLOMH		3.4E-05	HEATED CANISTER	FID
BENZENE		BLOIC		ND[1.0E-3]	HEATED CANISTER	FID
BENZENE		BLOID		ND[2.3E-3]	HEATED CANISTER	FID
BENZENE		BLOIE		ND[1.8E-2]	HEATED CANISTER	FID
BENZENE		BLOIF		ND[8.7E-3]	HEATED CANISTER	FID
BENZENE		BLOIG		ND[7.0E-3]	HEATED CANISTER	FID
NO. OF TESTS	DETECTS		RANGE	MEDIAN*		
10	4		ND to 4.2E-4	2.4E-06		
bis(2-ETHYLHEXYL)PHTHALATE		BLOK		ND	SEMI-VOST	
BROMODICHLOROMETHANE		BLOI	1 ppb	2.4E-06	VOST	
BROMOMETHANE		BLOI	2 ppb	2.8E-06	VOST	
BROMOMETHANE		BLOK	2.0 to 4.7 ppb	9.8E-06	VOST	
NO. OF TESTS	DETECTS		RANGE	MEDIAN		
2	2		2.8E-06 to 9.8E-06	6.3E-06		
BUTYL BENZYL PHTHALATE		BLOK		ND	SEMI-VOST	
n-BUTYRALDEHYDE		BLOK	1.75 to 2.66 ppm	5.5E-03	M0011	
CARBON DISULFIDE		BLOI	ND to 0.1 lb/hr	2.5E-03	M16	
CARBON DISULFIDE		BLOK	173 to 321 ppb	6.2E-04	VOST	
CARBON DISULFIDE		BLOIC	0.0010 to 0.0012	1.1E-03	HEATED CANISTER	FPD
CARBON DISULFIDE		BLOIG	0.0041 to 0.0045	4.3E-03	HEATED CANISTER	FPD
NO. OF TESTS	DETECTS		RANGE	MEDIAN		
4	4		ND to 0.0045	1.8E-03		
CARBON TETRACHLORIDE		BLOMD		ND[1.3E-3]	HEATED CANISTER	FID
CARBON TETRACHLORIDE		BLOMH		ND[6.4E-4]	HEATED CANISTER	FID
CARBON TETRACHLORIDE		BLOIC		ND[1.9E-3]	HEATED CANISTER	FID
CARBON TETRACHLORIDE		BLOID		ND[4.5E-3]	HEATED CANISTER	FID
CARBON TETRACHLORIDE		BLOIE		ND[3.6E-2]	HEATED CANISTER	FID
CARBON TETRACHLORIDE		BLOIF		ND[1.7E-2]	HEATED CANISTER	FID
CARBON TETRACHLORIDE		BLOIG		ND[1.4E-2]	HEATED CANISTER	FID
NO. OF TESTS	DETECTS		RANGE	MEDIAN		
7	0		ND	ND		
CARBONYL SULFIDE		BLOIC	0.0010 to 0.0012	1.1E-03	HEATED CANISTER	FPD
CARBONYL SULFIDE		BLOIG	0.0041 to 0.0045	4.3E-03	HEATED CANISTER	FPD
NO. OF TESTS	DETECTS		RANGE	MEDIAN		
2	2		1.0E-03 to 4.5E-03	2.7E-03		
3-CARENE		BLOI		ND[2.5E-03]	M18	
CHLORINE		BLOK	0.031 to 0.041 ppm	8.7E-05	M26A	Suspect data: Do Not Use
CHLOROBENZENE		BLOMD		5.2E-05	HEATED CANISTER	FID, U
CHLOROBENZENE		BLOMH		ND[3.9E-5]	HEATED CANISTER	FID
CHLOROBENZENE		BLOIC		ND[1.4E-3]	HEATED CANISTER	FID

TABLE 11 SUMMARY OF 'AIR TOXIC' EMISSIONS FROM BLACK LIQUOR OXIDATION TANK VENTS, CONTD.

			EMISSIONS			
VOLATILE ORGANIC COMPOUND		MILL CODE	RANGE lb/ton BLS	AVG lb/ton BLS	TEST METHOD	COMMENTS
CHLOROBENZENE		BLOID		ND[3.3E-3]	HEATED CANISTER	FID
CHLOROBENZENE		BLOIE		ND[2.6E-2]	HEATED CANISTER	FID
CHLOROBENZENE		BLOIF		ND[1.3E-2]	HEATED CANISTER	FID
CHLOROBENZENE		BLOIG		ND[1.0E-2]	HEATED CANISTER	FID
NO. OF TESTS	DETECTS		RANGE	MEDIAN**		
7	1		ND to 5.2E-05	2.6E-06		
CHLOROFORM		BLOI	22 ppb	3.9E-05	VOST	
CHLOROFORM		BLOI	0.11 to 0.71 ppb	1.3E-06	VOST	
CHLOROFORM		BLOMD		ND[9.7E-4]	HEATED CANISTER	FID
CHLOROFORM		BLOMH		ND[5.0E-4]	HEATED CANISTER	FID
CHLOROFORM		BLOIC		ND[3.0E-3]	HEATED CANISTER	FID
CHLOROFORM		BLOID		ND[7.0E-3]	HEATED CANISTER	FID
CHLOROFORM		BLOIE		ND[5.5E-2]	HEATED CANISTER	FID
CHLOROFORM		BLOIF		ND[2.7E-2]	HEATED CANISTER	FID
CHLOROFORM		BLOIG		ND[2.2E-2]	HEATED CANISTER	FID
NO. OF TESTS	DETECTS		RANGE	MEDIAN**		
9	2		ND to 3.9E-05	1.7E-07		
CHLOROMETHANE		BLOI	92 ppb	6.8E-05	VOST	
CHLOROMETHANE		BLOK	337 to 670 ppb	9.1E-04	VOST	
NO. OF TESTS	DETECTS		RANGE	MEDIAN		
2	2		6.8E-05 to 9.1E-04	4.9E-04		
o-CRESOL		BLOIC		ND[1.4E-3]	HEATED CANISTER	FID
o-CRESOL		BLOID		ND[3.2E-3]	HEATED CANISTER	FID
o-CRESOL		BLOIE		ND[2.5E-2]	HEATED CANISTER	FID
o-CRESOL		BLOIF		ND[1.2E-2]	HEATED CANISTER	FID
o-CRESOL		BLOIG		ND[9.8E-3]	HEATED CANISTER	FID
NO. OF TESTS	DETECTS		RANGE	MEDIAN		
5	0		ND	ND		
CROTONALDEHYDE		BLOK	35 to 142 ppb	1.7E-04	M0011	SYNONYM - 2-BUTENAL
CROTONALDEHYDE		BLOIE	ND to 1.5E-04	8.0E-05	IMPINGER	DNPH
CROTONALDEHYDE		BLOIE		ND[3.7E-4]	IMPINGER	DNPH
CROTONALDEHYDE		BLOIF	3.0E-04 to 6.0E-04	4.7E-04	IMPINGER	DNPH
CROTONALDEHYDE		BLOIG		ND[1.3E-4]	IMPINGER	DNPH
NO. OF TESTS	DETECTS		RANGE	MEDIAN		
5	3		ND to 6.0E-04	8.0E-05		
CUMENE		BLOI		ND[2.5E-3]	M18	
CUMENE		BLOIC		ND[1.5E-3]	HEATED CANISTER	FID
CUMENE		BLOID		ND[3.6E-3]	HEATED CANISTER	FID
CUMENE		BLOIE		ND[2.8E-2]	HEATED CANISTER	FID
CUMENE		BLOIF		ND[1.3E-2]	HEATED CANISTER	FID
CUMENE		BLOIG		ND[1.1E-2]	HEATED CANISTER	FID
NO. OF TESTS	DETECTS		RANGE	MEDIAN		
6	0		ND	ND		
p-CYMENE		BLOI	7 ppb	1.1E-05	VOST	
p-CYMENE		BLOK	2.2 to 4.4 ppb	1.3E-05	VOST	
NO. OF TESTS	DETECTS		RANGE	MEDIAN		
2	2		1.1E-05 to 1.3E-05	1.2E-05		
CYCLOHEXANONE		BLOID		ND[1.5E-4]	IMPINGER	DNPH
CYCLOHEXANONE		BLOIE		ND[4.9E-4]	IMPINGER	DNPH
CYCLOHEXANONE		BLOIF		ND[1.2E-4]	IMPINGER	DNPH
CYCLOHEXANONE		BLOIG		ND[1.3E-4]	IMPINGER	DNPH
NO. OF TESTS	DETECTS		RANGE	MEDIAN		
4	0		ND	ND		

TABLE 11 SUMMARY OF 'AIR TOXIC' EMISSIONS FROM BLACK LIQUOR OXIDATION TANK VENTS, CONTD.

VOLATILE ORGANIC COMPOUND		MILL CODE	EMISSIONS RANGE lb/ton BLS	AVG lb/ton BLS	TEST METHOD	COMMENTS
DIBROMOMETHANE		BLOI	1 ppb	2.6E-06	VOST	
Di-n-BUTYL PHTHALATE		BLOK	ND to 2.2 ppb	1.2E-05	SEMIVOST	
1,4-DICHLOROBENZENE		BLOK		ND	SEMIVOST	
1,2-DICHLOROETHANE		BLOMD		ND[2.7E-4]	HEATED CANISTER	FID
1,2-DICHLOROETHANE		BLOMH		ND[1.4E-4]	HEATED CANISTER	FID
NO. OF TESTS	DETECTS		RANGE	MEDIAN		
2	0		ND	ND		
2,5-DIMETHYL BENZALDEHYDE		BLOK	11.8 to 19.2 ppb	6.9E-05	M0011	
DIMETHYL DISULFIDE		BLOI	0.005 to 0.0125	1.0E-02	M16	
DIMETHYL DISULFIDE		BLOK	948 to 1510 ppb	3.6E-03	VOST	
DIMETHYL DISULFIDE		BLOMD		1.6E-02	HEATED CANISTER	FID
DIMETHYL DISULFIDE		BLOMH		2.4E-03	HEATED CANISTER	FID
DIMETHYL DISULFIDE		BLOIC	0.020 to 0.030	2.6E-02	HEATED CANISTER	FID
DIMETHYL DISULFIDE		BLOID	0.064 to 0.158	1.3E-01	HEATED CANISTER	FID
DIMETHYL DISULFIDE		BLOIE		ND[0.022]	HEATED CANISTER	FID
DIMETHYL DISULFIDE		BLOIF	0.320 to 0.434	3.7E-01	HEATED CANISTER	FID
DIMETHYL DISULFIDE		BLOIG	0.056 to 0.134	8.4E-02	HEATED CANISTER	FID
NO. OF TESTS	DETECTS		RANGE	MEDIAN		
9	8		ND to 0.434	1.6E-02		
DIMETHYLPHTHALATE		BLOK	ND		SEMIVOST	
DIMETHYL SULFIDE		BLOI	ND to 0.0075	2.5E-03	M16	
DIMETHYL SULFIDE		BLOK	299 to 418 ppb	7.6E-04	VOST	
DIMETHYL SULFIDE		BLOMD		9.0E-03	HEATED CANISTER	FID
DIMETHYL SULFIDE		BLOMH		ND[1.1E-3]	HEATED CANISTER	FID
DIMETHYL SULFIDE		BLOIC		ND[7.9E-4]	HEATED CANISTER	FID
DIMETHYL SULFIDE		BLOID	0.070 to 0.075	7.4E-02	HEATED CANISTER	FID
DIMETHYL SULFIDE		BLOIE		ND[1.4E-2]	HEATED CANISTER	FID
DIMETHYL SULFIDE		BLOIF	0.012 to 0.019	1.5E-02	HEATED CANISTER	FID
DIMETHYL SULFIDE		BLOIG	ND to 0.013	6.3E-03	HEATED CANISTER	FID
NO. OF TESTS	DETECTS		RANGE	MEDIAN		
9	6		ND to 0.075	2.5E-03		
ETHANOL		BLOF	ND to 0.0324	1.4E-02	M18	
ETHANOL		BLOI	ND to 2.5E-03	2.5E-03	M18	
ETHANOL		BLOIC	ND to 0.0007	5.3E-04	HEATED CANISTER	FID
ETHANOL		BLOID	0.002 to 0.005	3.7E-03	HEATED CANISTER	FID
ETHANOL		BLOIE		ND[1.1E-2]	HEATED CANISTER	FID
ETHANOL		BLOIF		ND[5.2E-3]	HEATED CANISTER	FID
ETHANOL		BLOIG		ND[4.2E-3]	HEATED CANISTER	FID
NO. OF TESTS	DETECTS		RANGE	MEDIAN		
7	4		ND to 3.2E-2	5.3E-04		
ETHYL BENZENE		BLOF	ND to 0.025	9.2E-03	M18	
ETHYL BENZENE		BLOI	1 ppb	1.5E-06	VOST	
ETHYL BENZENE		BLOK	0.27 to 0.48 ppb	1.2E-06	VOST	
ETHYL BENZENE		BLOID		ND[3.1E-3]	HEATED CANISTER	FID
ETHYL BENZENE		BLOIE		ND[2.5E-2]	HEATED CANISTER	FID
NO. OF TESTS	DETECTS		RANGE	MEDIAN		
5	3		ND to 0.025	1.2E-06		

TABLE 11 SUMMARY OF 'AIR TOXIC' EMISSIONS FROM BLACK LIQUOR OXIDATION TANK VENTS, CONTD.

			EMISSIONS			
VOLATILE ORGANIC		MILL	RANGE	AVG	TEST	
COMPOUND		CODE	lb/ton BLS	lb/ton BLS	METHOD	COMMENTS
FORMALDEHYDE		BLOF		ND [1.2E-03]	RTI DRAFT	
FORMALDEHYDE		BLOK	91 to 124 ppb	1.0E-03	M0011	
FORMALDEHYDE		BLOIC		ND[2.2E-4]	HEATED CANISTER	FID
FORMALDEHYDE		BLOID	0.0003 to 0.0006	4.5E-04	HEATED CANISTER	FID
FORMALDEHYDE		BLOIE	0.0006 to 0.0009	7.3E-04	HEATED CANISTER	FID
FORMALDEHYDE		BLOIF	0.0009 to 0.0014	1.1E-03	HEATED CANISTER	FID
FORMALDEHYDE		BLOIG	0.0003 to 0.0014	7.8E-04	HEATED CANISTER	FID
NO. OF TESTS	DETECTS		RANGE	MEDIAN		
7	5		ND to 0.0014	7.3E-04		
HEXACHLOROCYCLOPENTADIENE		BLOIC		ND[3.5E-3]	HEATED CANISTER	FID
HEXACHLOROCYCLOPENTADIENE		BLOIF		ND[3.1E-2]	HEATED CANISTER	FID
HEXACHLOROCYCLOPENTADIENE		BLOIG		ND[2.5E-2]	HEATED CANISTER	FID
NO. OF TESTS	DETECTS		RANGE	MEDIAN		
3	0		ND	ND		
HEXACHLOROETHANE		BLOIC		ND[3.0E-3]	HEATED CANISTER	FID
HEXACHLOROETHANE		BLOIF		ND[2.7E-2]	HEATED CANISTER	FID
HEXACHLOROETHANE		BLOIG		ND[2.1E-2]	HEATED CANISTER	FID
NO. OF TESTS	DETECTS		RANGE	MEDIAN		
3	0		ND	ND		
HEXALDEHYDE		BLOK	32 to 51 ppb	1.4E-04	M0011	
n-HEXANE		BLOI	189 ppb	2.5E-04	VOST	
n-HEXANE		BLOIC		ND[1.1E-3]	HEATED CANISTER	FID
n-HEXANE		BLOID		ND[2.6E-3]	HEATED CANISTER	FID
n-HEXANE		BLOIE		ND[2.0E-2]	HEATED CANISTER	FID
n-HEXANE		BLOIF		ND[9.7E-3]	HEATED CANISTER	FID
n-HEXANE		BLOIG		ND[7.8E-3]	HEATED CANISTER	FID
NO. OF TESTS	DETECTS		RANGE	MEDIAN**		
6	1		ND to 2.5E-04	1.5E-05		
2-HEXANONE		BLOK	12.2 to 25.5 ppb	5.8E-05	VOST	
HYDROGEN CHLORIDE		BLOK	0.16 to 0.21 ppm	2.3E-04	M26A	Suspect data: Do Not Use
HYDROGEN FLUORIDE		BLOK		ND[1.8E-05]	M26A	
HYDROGEN SULFIDE		BLOI	ND to 0.4 lb/hr	5.0E-03	M16	
HYDROGEN SULFIDE		BLOIC	ND to 0.0007	3.2E-04	HEATED CANISTER	FID
HYDROGEN SULFIDE		BLOIG	0.043 to 0.053	4.8E-02	HEATED CANISTER	FID
NO. OF TESTS	DETECTS		RANGE	MEDIAN		
3	3		ND to 0.053	5.0E-03		
ISOPROPYL ALCOHOL		BLOID		ND[1.8E-3]	HEATED CANISTER	FID
ISOPROPYL ALCOHOL		BLOIE		ND[1.4E-2]	HEATED CANISTER	FID
NO. OF TESTS	DETECTS		RANGE	MEDIAN		
2	0		ND	ND		
METHANOL		BLOA	0.81 to 0.94	8.7E-01	IMPINGER	NCASI METHOD
METHANOL		BLOB	0.12 to 0.22	1.7E-01	IMPINGER	NCASI METHOD
METHANOL		BLOD	-	1.2E-01	NA	
METHANOL		BLOE	-	2.5E-01	NA	

TABLE 11 SUMMARY OF 'AIR TOXIC' EMISSIONS FROM BLACK LIQUOR OXIDATION TANK VENTS, CONTD.

VOLATILE ORGANIC COMPOUND		MILL CODE	EMISSIONS RANGE lb/ton BLS	AVG lb/ton BLS	TEST METHOD	COMMENTS
METHANOL		BLOF	0.86 to 2.10	1.4E+00	M18	
METHANOL		BLOH	0.70 to 0.84	7.7E-01	MOD NIOSH 2000	
METHANOL		BLOI	0.035 to 0.0475	4.5E-02	M18	
METHANOL		BLOJ	0.20 to 0.34	2.9E-01	MOD NIOSH 2000	
METHANOL		BLOK	0.15 to 0.17	1.6E-01	IMPINGER	NCASI METHOD
METHANOL		BLOMD		3.3E-01	HEATED CANISTER	FID
METHANOL		BLOMH		2.1E-01	HEATED CANISTER	FID
METHANOL		BLOIC	0.070 to 0.095	8.7E-02	HEATED CANISTER	FID. coeluted with acetaldehyde
METHANOL		BLOID	0.202 to 0.254	2.4E-01	HEATED CANISTER	FID
METHANOL		BLOIE	0.646 to 0.929	7.6E-01	HEATED CANISTER	FID
METHANOL		BLOIF	1.148 to 1.637	1.3E+00	HEATED CANISTER	FID. coeluted with acetaldehyde
METHANOL		BLOIG	0.389 to 0.476	4.4E-02	HEATED CANISTER	FID. coeluted with acetaldehyde
NO. OF TESTS	DETECTS		RANGE	MEDIAN		
16	16		0.035 to 2.10	2.4E-01		
METHYL ETHYL KETONE		BLOA	0.013 to 0.014	1.4E-02	NCASI METHOD	
METHYL ETHYL KETONE		BLOB	0.005 to 0.006	5.5E-03	NCASI METHOD	
METHYL ETHYL KETONE		BLOF	0.025 to 0.084	4.4E-02	M18	
METHYL ETHYL KETONE		BLOI	883 ppb	9.5E-04	VOST	
METHYL ETHYL KETONE		BLOJ	ND to 0.006	1.8E-03	MOD NIOSH 2000	
METHYL ETHYL KETONE		BLOK	0.89 to 2.12 ppm	3.2E-03	VOST	3.0E-03 by M0011
METHYL ETHYL KETONE		BLOMD		7.2E-03	HEATED CANISTER	FID
METHYL ETHYL KETONE		BLOMH		7.7E-03	HEATED CANISTER	FID
METHYL ETHYL KETONE		BLOIC		ND[9.1E-4]	HEATED CANISTER	FID, 2.3E-04 by DNPH METHOD
METHYL ETHYL KETONE		BLOID	0.005 to 0.006	5.5E-03	HEATED CANISTER	FID, 4.1E-03 by DNPH METHOD
METHYL ETHYL KETONE		BLOIE	ND to 0.020	1.6E-02	HEATED CANISTER	FID, 9.0E-03 by DNPH METHOD
METHYL ETHYL KETONE		BLOIF	0.033 to 0.043	3.6E-02	HEATED CANISTER	FID, 1.5E-03 by DNPH METHOD
METHYL ETHYL KETONE		BLOIG	0.008 to 0.009	8.7E-03	HEATED CANISTER	FID, ND[1.3E-04] by DNPH METH.
NO. OF TESTS	DETECTS		RANGE	MEDIAN		
13	12		ND to 0.084	7.2E-03		
METHYL ISOBUTYL KETONE		BLOF		ND[1.2E-3]	RTI DRAFT	
METHYL ISOBUTYL KETONE		BLOK		5.8E-05	VOST	
METHYL ISOBUTYL KETONE		BLOMD		2.3E-04	HEATED CANISTER	FID
METHYL ISOBUTYL KETONE		BLOMH		1.5E-04	HEATED CANISTER	FID
METHYL ISOBUTYL KETONE		BLOIC		ND[1.3E-3]	HEATED CANISTER	FID, ND[1.5E-04] by DNPH METH.
METHYL ISOBUTYL KETONE		BLOID		ND[2.9E-3]	HEATED CANISTER	FID, ND[1.5E-04] by DNPH METH.
METHYL ISOBUTYL KETONE		BLOIE		ND[2.3E-2]	HEATED CANISTER	FID, ND[4.9E-04] by DNPH METH.
METHYL ISOBUTYL KETONE		BLOIF		ND[1.1E-2]	HEATED CANISTER	FID, 3.1E-04 by DNPH METHOD
METHYL ISOBUTYL KETONE		BLOIG		ND[9.0E-3]	HEATED CANISTER	FID, ND[1.3E-04] by DNPH METH.
NO. OF TESTS	DETECTS		RANGE	MEDIAN*		
9	3		ND to 2.3E-4	3.0E-05		
METHYL MERCAPTAN		BLOI	0.01 to 0.0175	1.5E-02	M16	
METHYL MERCAPTAN		BLOMD		1.1E-02	HEATED CANISTER	FID
METHYL MERCAPTAN		BLOMH		ND[8.4E-4]	HEATED CANISTER	FID
METHYL MERCAPTAN		BLOIC	0.004 to 0.006	5.2E-03	HEATED CANISTER	FID
METHYL MERCAPTAN		BLOID		ND[1.4E-3]	HEATED CANISTER	FID
METHYL MERCAPTAN		BLOIE		ND[1.1E-2]	HEATED CANISTER	FID
METHYL MERCAPTAN		BLOIF		ND[5.4E-3]	HEATED CANISTER	FID
METHYL MERCAPTAN		BLOIG		ND[4.4E-3]	HEATED CANISTER	FID
NO. OF TESTS	DETECTS		RANGE	MEDIAN*		
8	3		ND to 0.0175	3.6E-03		
4-METHYL-2-PENTANONE		BLOK	13.0 to 18.8 ppb	5.1E-05	VOST	
2-METHYLPHENOL		BLOK	ND			
METHYLENE CHLORIDE		BLOI	32 ppb	4.1E-05	VOST	
METHYLENE CHLORIDE		BLOK	272 to 507 ppb	1.1E-03	VOST	

TABLE 11 SUMMARY OF 'AIR TOXIC' EMISSIONS FROM BLACK LIQUOR OXIDATION TANK VENTS, CONTD.

			EMISSIONS			
VOLATILE ORGANIC		MILL	RANGE	AVG	TEST	
COMPOUND		CODE	lb/ton BLS	lb/ton BLS	METHOD	COMMENTS
METHYLENE CHLORIDE		BLOMD		ND[4.9E-4]	HEATED CANISTER	FID
METHYLENE CHLORIDE		BLOMH		ND[2.5E-4]	HEATED CANISTER	FID
METHYLENE CHLORIDE		BLOIC		ND[1.1E-3]	HEATED CANISTER	FID
METHYLENE CHLORIDE		BLOID	ND to 0.0096	4.8E-03	HEATED CANISTER	FID
METHYLENE CHLORIDE		BLOIE		ND[2.0E-2]	HEATED CANISTER	FID
METHYLENE CHLORIDE		BLOIF		ND[9.5E-3]	HEATED CANISTER	FID
METHYLENE CHLORIDE		BLOIG		ND[7.7E-3]	HEATED CANISTER	FID
NO. OF TESTS	DETECTS		RANGE	MEDIAN*		
9	3		ND to 0.0096	4.4E-05		
NAPHTHALENE		BLOF	ND to 0.020	8.1E-03	M18	
NAPHTHALENE		BLOK		ND	SEMIVOST	
NO. OF TESTS	DETECTS		RANGE	MEDIAN		
2	1		ND to 0.02	8.1E-03		
PHENOL		BLOE		1.7E-03	NA	
PHENOL		BLOK	88 to 165 ppb	3.5E-04	SEMIVOST	
PHENOL		BLOIC		ND[1.2E-3]	HEATED CANISTER	FID
PHENOL		BLOID		ND[2.8E-3]	HEATED CANISTER	FID
PHENOL		BLOIE		ND[2.2E-2]	HEATED CANISTER	FID
PHENOL		BLOIF		ND[1.1E-2]	HEATED CANISTER	FID
PHENOL		BLOIG		ND[8.5E-3]	HEATED CANISTER	FID
NO. OF TESTS	DETECTS		RANGE	MEDIAN**		
7	2		ND to 0.0017	6.7E-05		
ALPHA-PINENE		BLOF	ND to 0.006	3.6E-03	M18	
ALPHA-PINENE		BLOI	39 ppb	8.0E-05	VOST	
ALPHA-PINENE		BLOK	81.5 to 149 ppb	4.7E-04	VOST	5.1E-04 by SEMI-VOST
ALPHA-PINENE		BLOIC		ND[1.7E-3]	HEATED CANISTER	FID
ALPHA-PINENE		BLOIF		ND[1.5E-2]	HEATED CANISTER	FID
ALPHA-PINENE		BLOIG		ND[1.2E-2]	HEATED CANISTER	FID
NO. OF TESTS	DETECTS		RANGE	MEDIAN*		
6	3		ND to 0.006	4.3E-05		
BETA-PINENE		BLOF	ND to 0.009	3.0E-03	M18	
BETA-PINENE		BLOI	17 ppb	3.4E-05	VOST	
BETA-PINENE		BLOK	20.3 to 42.9 ppb	1.2E-04	VOST	7.3E-05 by SEMI-VOST
BETA-PINENE		BLOIC		ND[1.7E-3]	HEATED CANISTER	FID
BETA-PINENE		BLOIF		ND[1.5E-2]	HEATED CANISTER	FID
BETA-PINENE		BLOIG		ND[1.2E-2]	HEATED CANISTER	FID
NO. OF TESTS	DETECTS		RANGE	MEDIAN*		
6	3		ND to 0.009	1.2E-05		
PROPIONALDEHYDE		BLOK	ND to 56.8 ppb	7.3E-05	M0011	SYNONYM - PROPANAL
PROPIONALDEHYDE		BLOID		ND[7.3E-4]	IMPINGER	DNPH
PROPIONALDEHYDE		BLOID	0.0019 to 0.0020	1.9E-03	IMPINGER	DNPH
PROPIONALDEHYDE		BLOIE	0.0014 to 0.0058	3.7E-03	IMPINGER	DNPH
PROPIONALDEHYDE		BLOIF	0.0015 to 0.0020	1.7E-03	IMPINGER	DNPH
PROPIONALDEHYDE		BLOIG	0.0005 to 0.0023	1.3E-03	IMPINGER	DNPH
NO. OF TESTS	DETECTS		RANGE	MEDIAN		
6	5		ND to 0.0058	1.5E-03		
STYRENE		BLOI	3 ppb	4.7E-06	VOST	
STYRENE		BLOMD		4.7E-04	HEATED CANISTER	FID
STYRENE		BLOMH		3.7E-05	HEATED CANISTER	FID
NO. OF TESTS	DETECTS		RANGE	MEDIAN		
3	3		4.7E-6 to 4.7E-4	3.7E-05		

TABLE 11 SUMMARY OF 'AIR TOXIC' EMISSIONS FROM BLACK LIQUOR OXIDATION TANK VENTS, CONTD.

VOLATILE ORGANIC COMPOUND		MILL CODE	EMISSIONS RANGE lb/ton BLS	EMISSIONS AVG lb/ton BLS	TEST METHOD	COMMENTS
ALPHA-TERPINEOL		BLOF		ND[1.2E-03]	M18	
ALPHA-TERPINEOL		BLOK	ND to 94.5 ppb	2.9E-04	SEMI-VOST	
NO. OF TESTS	DETECTS		RANGE	MEDIAN		
2	1		ND to 2.9E-04	2.9E-04		
TETRACHLOROETHYLENE		BLOMD		ND[3.4E-4]	HEATED CANISTER	FID
TETRACHLOROETHYLENE		BLOMH		ND[1.7E-4]	HEATED CANISTER	FID
NO. OF TESTS	DETECTS		RANGE	MEDIAN		
2	0		ND	ND		
o-TOLUALDEHYDE		BLOK	91 to 163 ppb	4.7E-04	M0011	
m,p-TOLUALDEHYDE		BLOK	ND to 37.4 ppb	5.8E-05	M0011	
TOLUENE		BLOF	ND to 0.006	2.5E-03	M18	
TOLUENE		BLOI	37 ppb	5.1E-05	VOST	
TOLUENE		BLOK	9.1 to 20.2 ppb	4.4E-05	VOST	
TOLUENE		BLOMD		4.5E-04	HEATED CANISTER	FID
TOLUENE		BLOMH		7.5E-05	HEATED CANISTER	FID
TOLUENE		BLOIC		ND[1.2E-3]	HEATED CANISTER	FID
TOLUENE		BLOID		ND[2.7E-3]	HEATED CANISTER	FID
TOLUENE		BLOIE		ND[2.1E-2]	HEATED CANISTER	FID
TOLUENE		BLOIF		ND[1.0E-2]	HEATED CANISTER	FID
TOLUENE		BLOIG		ND[8.3E-3]	HEATED CANISTER	FID
NO. OF TESTS	DETECTS		RANGE	MEDIAN*		
10	5		ND to 6.0E-03	1.9E-05		
1,2,4-TRICHLOROBENZENE		BLOMD		5.3E-04	HEATED CANISTER	FID
1,2,4-TRICHLOROBENZENE		BLOMH		2.5E-04	HEATED CANISTER	FID, U
NO. OF TESTS	DETECTS		RANGE	MEDIAN		
2	2		2.5E-04 to 5.3E-04	3.9E-04		
1,1,1-TRICHLOROETHANE		BLOI		ND	VOST	
1,1,1-TRICHLOROETHANE		BLOK	0.30 to 1.31 ppb	2.8E-06	VOST	
1,1,1-TRICHLOROETHANE		BLOMD		ND[2.7E-4]	HEATED CANISTER	FID
1,1,1-TRICHLOROETHANE		BLOMH		ND[1.4E-4]	HEATED CANISTER	FID
1,1,1-TRICHLOROETHANE		BLOIC		ND[1.7E-3]	HEATED CANISTER	FID
1,1,1-TRICHLOROETHANE		BLOID		ND[3.9E-3]	HEATED CANISTER	FID
1,1,1-TRICHLOROETHANE		BLOIE		ND[3.1E-2]	HEATED CANISTER	FID
1,1,1-TRICHLOROETHANE		BLOIF		ND[1.5E-2]	HEATED CANISTER	FID
1,1,1-TRICHLOROETHANE		BLOIG		ND[1.3E-2]	HEATED CANISTER	FID
NO. OF TESTS	DETECTS		RANGE	MEDIAN**		
9	2		ND to 5.4E-06	1.1E-07		
1,1,2-TRICHLOROETHANE		BLOMD		ND[2.7E-4]	HEATED CANISTER	FID
1,1,2-TRICHLOROETHANE		BLOMH		ND[1.4E-4]	HEATED CANISTER	FID
1,1,2-TRICHLOROETHANE		BLOIC		ND[1.7E-3]	HEATED CANISTER	
1,1,2-TRICHLOROETHANE		BLOID		ND[3.9E-3]	HEATED CANISTER	
1,1,2-TRICHLOROETHANE		BLOIE		ND[3.1E-2]	HEATED CANISTER	
1,1,2-TRICHLOROETHANE		BLOIF		ND[1.5E-2]	HEATED CANISTER	
1,1,2-TRICHLOROETHANE		BLOIG		ND[1.2E-2]	HEATED CANISTER	
NO. OF TESTS	DETECTS		RANGE	MEDIAN		
7	0		ND	ND		

TABLE 11 SUMMARY OF 'AIR TOXIC' EMISSIONS FROM BLACK LIQUOR OXIDATION TANK VENTS, CONTD.

VOLATILE ORGANIC COMPOUND		MILL CODE	EMISSIONS RANGE lb/ton BLS	AVG lb/ton BLS	TEST METHOD	COMMENTS
TRICHLOROETHYLENE		BLOMD		2.8E-04	HEATED CANISTER	FID, U
TRICHLOROETHYLENE		BLOMH		ND[1.4E-4]	HEATED CANISTER	FID
TRICHLOROETHYLENE		BLOIC		ND[1.7E-3]	HEATED CANISTER	FID
TRICHLOROETHYLENE		BLOID		ND[3.9E-3]	HEATED CANISTER	FID
TRICHLOROETHYLENE		BLOIE		ND[3.0E-2]	HEATED CANISTER	FID
TRICHLOROETHYLENE		BLOIF		ND[1.5E-2]	HEATED CANISTER	FID
TRICHLOROETHYLENE		BLOIG		ND[1.2E-2]	HEATED CANISTER	FID
NO. OF TESTS	DETECTS		RANGE	MEDIAN**		
7	1		ND to 2.8E-04	1.4E-05		
TRICHLOROFLUOROMETHANE		BLOI	5 ppb	1.0E-05	VOST	
TRICHLOROFLUOROMETHANE		BLOK	0.60 to 0.87 ppb	3.7E-06	VOST	
NO. OF TESTS	DETECTS		RANGE	MEDIAN		
2	2		2.9E-06 to 1.0E-05	6.9E-06		
VALERALDEHYDE		BLOK	107 to 335 ppb	6.6E-04	M0011	SYNONYM - PENTANAL
VALERALDEHYDE		BLOIE	0.001 to 0.0012	1.1E-03	IMPINGER	DNPH
VALERALDEHYDE		BLOIE	0.001 to 0.004	2.6E-03	IMPINGER	DNPH
VALERALDEHYDE		BLOIF	0.0006 to 0.0012	9.2E-04	IMPINGER	DNPH
VALERALDEHYDE		BLOIG	ND to 0.0009	4.2E-04	IMPINGER	DNPH
NO. OF TESTS	DETECTS		RANGE	MEDIAN		
5	5		ND to 0.004	9.2E-04		
ISOVALERALDEHYDE		BLOK	225 to 304 ppb	7.6E-04	M0011	
o-XYLENE		BLOF	ND to 0.029	1.0E-02	M18	
o-XYLENE		BLOI	1 ppb	1.6E-06	VOST	
o-XYLENE		BLOMD		4.4E-04	HEATED CANISTER	FID
o-XYLENE		BLOMH		5.6E-05	HEATED CANISTER	FID
o-XYLENE		BLOIC		ND[1.3E-3]	HEATED CANISTER	FID
o-XYLENE		BLOID		ND[3.1E-3]	HEATED CANISTER	FID
o-XYLENE		BLOIE		ND[2.5E-2]	HEATED CANISTER	FID
o-XYLENE		BLOIF		ND[1.2E-2]	HEATED CANISTER	FID
o-XYLENE		BLOIG		ND[9.6E-3]	HEATED CANISTER	FID
NO. OF TESTS	DETECTS		RANGE	MEDIAN*		
9	4		ND to 0.029	5.2E-07		
m,p-XYLENE		BLOF		ND[1.2E-3]	M18	
m,p-XYLENE		BLOI	ND to 0.023	7.6E-03	M18	
m,p-XYLENE		BLOK	2.9 to 4.7 ppb	1.2E-05	VOST	
m,p-XYLENE		BLOMD		3.7E-04	HEATED CANISTER	FID
m,p-XYLENE		BLOMH		1.1E-04	HEATED CANISTER	FID
m,p-XYLENE		BLOIC		ND[1.3E-3]	HEATED CANISTER	FID
m,p-XYLENE		BLOID		ND[3.1E-3]	HEATED CANISTER	FID
m,p-XYLENE		BLOIE		ND[2.5E-2]	HEATED CANISTER	FID
m,p-XYLENE		BLOIF		ND[1.2E-2]	HEATED CANISTER	FID
m,p-XYLENE		BLOIG		ND[9.6E-3]	HEATED CANISTER	FID
NO. OF TESTS	DETECTS		RANGE	MEDIAN*		
10	4		ND to 0.023	2.2E-06		
TERPENES		BLOMD		2.3E-02	HEATED CANISTER	FID
TERPENES		BLOMH		3.3E-01	HEATED CANISTER	FID
TERPENES		BLOID	ND to 0.005	3.8E-03	HEATED CANISTER	FID
TERPENES		BLOIE	0.066 to 0.134	1.1E-01	HEATED CANISTER	FID
TERPENES		BLOIF		ND[1.5E-2]	HEATED CANISTER	FID
NO. OF TESTS	DETECTS		RANGE	MEDIAN		
5	4		ND to 3.3E-1	2.3E-02		

TABLE 11 SUMMARY OF 'AIR TOXIC' EMISSIONS FROM BLACK LIQUOR OXIDATION TANK VENTS, CONTD.

VOLATILE ORGANIC COMPOUND		MILL CODE	EMISSIONS RANGE lb/ton BLS	AVG lb/ton BLS	TEST METHOD	COMMENTS
			lb C/ton BLS	lb C/ton BLS		
TOTAL HYDROCARBONS		A		1.5E-01	M25	NCASI Tech. Bull. No. 646
TOTAL HYDROCARBONS		B		2.9E-01	M25	NCASI Tech. Bull. No. 646
TOTAL HYDROCARBONS		D		2.3E-02	M25A	NCASI Tech. Bull. No. 646
TOTAL HYDROCARBONS		H		3.3E-01	M25A	NCASI Tech. Bull. No. 646
TOTAL HYDROCARBONS		BLOK		5.4E-02	M25A	
TOTAL HYDROCARBONS		BLOIC	0.0119 to 0.014	1.3E-02	M25A	
NO. OF TESTS	DETECTS		RANGE	MEDIAN		
6	6		1.2E-02 to 3.3E-01	1.0E-01		

Notes
(a) U - unidentified and unconfirmed by GC/MSD
(b) For BLO units with codes BLOMX (X = A to Q) the heated canister gases were concentrated before analysis on the FID;
(c) For BLO units with codes BLOIX (X = A to J) the heated canister gases were not concentrated before analysis on the FID;
(d) For many mills actual BLS firing rates were unknown; lb/ADTP was converted to lb/ton BLS using a factor of 3250 lb BLS/ADTP;

MEDIAN - empirical median; MEDIAN* - "NORPLOT" median; MEDIAN** - "SDln" median

Table 6.5.2-1 TRS and VOC Emissions from Black Liquor Oxidation Systems (NCASI 2003a)

	No.	Range	Median	Mean
		(lb/ton BLS)		
Total TRS as S	10	6.0E-03 – 0.29	0.023	0.064
Dimethyl Disulfide	10	2.4E-03 – 0.40	0.014	0.068
Dimethyl Sulfide	10	ND – 0.12	6.2E-03	6.3E-03
Hydrogen Sulfide	4	2.0E-04 – 0.046	4.0E-03	7.9E-03
Methyl Mercaptan	9	ND – 0.022	0.01[1]	0.01[1]
Acetaldehyde	9	0.002 – 0.15	0.022	0.045
Formaldehyde	7	ND – 0.0011	7.3E-04	7.2E-04
Methanol	17	0.035 – 2.10	0.25	0.43
MEK	12	ND – 0.043	6.4E-03	8.9E-03
Terpenes	10	ND – 0.11	6.3E-03	7.0E-03
THCs as C[2]	7	1.8E-04 – 3.3E-01	0.054	0.12

Ton BLS – ton black liquor solids; No. – number of sources tested; ND – non-detect;
[1]NDs > 50%; statistically-derived average; [2]as measured by EPA M25A;

6.5.3 Kraft Recovery Furnaces

The first recovery furnace of the current industry-wide design was installed over 70 years ago. Since then there have been many incremental improvements and refinements to this design that have lowered emissions. TRS and particulate matter (PM) emissions received all of the attention until recent years, because of their readily observable nature (odor and visibility). Besides TRS and PM emissions, other significant emissions from the kraft recovery furnace include SO_2, NO_x, CO, volatile organic compounds (VOCs), including HAPs, and hydrochloric acid (HCl).

6.5.3.1 TRS Emissions

Until the mid-1970s, the recovery furnace was the predominant source of TRS emissions at every kraft mill. Although the recovery furnace still can be the largest TRS emission source, emissions have been greatly reduced over the last 25 years (Pinkerton 1999). Three factors have contributed to significant emission reductions. These are a) avoidance of firing black liquor solids at rates far above the furnace design capacity, which caused excessive H_2S emissions, b) widespread adoption of black liquor oxidation to minimize H_2S pick-up across direct contact evaporators, and c) the increasing number of NDCE-type furnace installations. In addition, there have been notable design improvements that have led to better combustion conditions in the furnace. Average concentrations of H_2S in recovery furnace flue gases now range from less than 1 to about 10 ppm for NDCEs (most NDCEs have TRS levels well below 5 ppm), and from 5 to 40 ppm for DCEs with black liquor oxidation. In the United States, TRS concentrations are normally reported at standard conditions of 0% moisture and 8% O_2 concentration rather than at actual stack conditions. Even with low TRS concentrations, the recovery furnace can still have significant mass emissions because of the high flue gas volumes.

For kraft recovery furnaces equipped with wet bottom ESPs, especially NDCE units, TRS emissions can also result from TRS compounds being picked up due to inadvertent contact between the unoxidized black liquor and the furnace flue gases as the latter pass through the ESP. Modifications to the duct work and internal baffling that minimize contact between the flue gases and the unoxidized liquor may alleviate this problem (EPA 1983). Other remedies include replacement of the liquor with water in the bottom of the ESP and conversion of the ESP from a wet bottom to a dry bottom.

6.5.3.2 Particulate Emissions

Recovery furnaces are designed and operated in a manner so as to ensure the presence of high levels of sodium fumes in order to capture the sulfur dioxide which is produced as a result of oxidation of reduced sulfur compounds. Consequently, recovery furnace flue gases contain high levels of particulate matter. The uncontrolled particulate matter load from recovery furnaces is highly variable and has been reported to range from 100 to 250 lb/ODTP for DCE furnaces and 200 to 450 lb/ODTP for non-DCE furnaces. The lower particulate loading from DCE furnaces is due to the capture of some particulate matter in the direct contact evaporator.

It has been reported that increasing liquor firing density (ton/day/ft^2) increases recovery furnace particulate loading (Nguyen and Rowbottom 1979). Other factors such as bed and furnace temperature, liquor solids, liquor composition and air distribution also affect uncontrolled particulate emissions from recovery furnaces.

Particulates generated in the recovery furnace are comprised mainly of sodium sulfate, with lesser amounts of sodium carbonate and sodium chloride. Similar potassium compounds are also generated, but in much lower amounts. Trace amounts of other metal compounds (e.g., magnesium, calcium and zinc) can be present. The sodium compounds originate from condensation of the gaseous sodium fume released from the smelt bed and from ash generated during combustion of liquor droplets carried upward in the furnace. A significant portion of the particulate material is sub-micron in size, which makes removal with add-on control devices more difficult. The material also has a "sticky" characteristic that promotes adhesion to boiler steam tubes and other surfaces. Soot blowing is required to dislodge this material.

Table 6.5.3.2-1 provides some data on composition of particulate matter emissions from recovery furnaces captured in electrostatic precipitators (Thompson, Paleologou, and Berry 1997). At the two mills in this study, one an interior mill and the other a coastal mill, much higher levels of chloride are seen compared with carbonate. The alkalinity of recovery furnace particulate matter (which depends on its carbonate content) is influenced by the sulfur dioxide concentrations in the flue gases. As the level of sulfur dioxide increases, it reacts with sodium carbonate to produce sodium sulfate.

The particulate matter produced in recovery furnaces is the result of complex reactions between sodium fumes and gases produced from combustion. From 67 to 77% and from 50 to 53% of the total mass of particulate in the flue gases is contributed by particles less than 10 μm and less than 2.5 μm in size, respectively (NCASI 2004).

Table 6.5.3.2-1 Composition of Particulate Matter Captured in Kraft Recovery Furnace Electrostatic Precipitators
(Thompson, Paleologou, and Berry 1997)

	ESP Catch Composition, wt. %	
	Interior Mill	Coastal Mill
Sodium	30.0	29.7
Potassium	3.3	3.2
Calcium	0.009	0.005
Iron	0.007	0.055
Manganese	0.003	0.002
Magnesium	0.003	0.003
Chromium	0.002	0.002
Nickel	N.D.	<0.001
Copper	N.D.	N.D.
Aluminum	N.D.	N.D.
Lead	<0.005	N.D.
Sulfate	63.5	46.6
Chloride	0.73	14.3
Carbonate	0.24	N.D.
Water	0.12	0.2
Organics	N.A.	0.09
Total	**97.9**	**94.2**

N.D. = not detected
N.A. = not analyzed

6.5.3.3 SO_2 Emissions

Black liquor contains a significant amount of sulfur, nominally 3 to 5% by weight of the dissolved solids. While the vast majority of this sulfur leaves the furnace in the smelt, a small fraction (generally under 1%) can escape in gaseous or particulate form. Average SO_2 concentrations in stack gases can range from nearly 0 to 500 ppm. Factors which influence SO_2 levels are liquor sulfidity, liquor solids content, stack oxygen content, furnace load, auxiliary fuel use, and furnace design. None of these factors has exhibited a consistent relationship with SO_2 emissions (NCASI 1991). On average, SO_2 emissions from NDCE units tend to be lower than from DCE units. Gaseous sulfuric acid may exist in recovery furnace flue gases as a result of a reaction between sulfur trioxide and water vapor, the SO_3 being formed in small amounts from further oxidation of SO_2. However, kraft recovery furnace gaseous H_2SO_4 concentrations are typically small, on the order of 1 ppm (NCASI 1980, 1995).

6.5.3.4 NO_x Emissions

Nitrogen in black liquor ranges from about 0.05 to 0.25% of the liquor solids content, typically averaging about 0.1%. During black liquor combustion, nearly three fourths of the liquor nitrogen is released during pyrolysis or devolatilization, partly as ammonia and partly as N_2. The NH_3 released partly oxidizes to NO and partly reduces to N_2. The remaining liquor nitrogen will be bound in the char residue, mostly as a reduced species in the salt residue or smelt. Forssen et al. (1997) have suggested that the oxidation of the NH_3 released during pyrolysis is perhaps the main contributor to the overall NO formation during normal black liquor combustion. Overall conversions of black liquor nitrogen to NO are quite low compared with other fuels, ranging from 10 to about 25%. NO_x levels are typically somewhat higher for NDCE furnaces than DCE units. Besides the older ages of the DCE units and perhaps a less robust combustion temperature environment, the reasons for this are unclear.

6.5.3.5 Ammonia Emissions

As the combustion gas passes upward through the oxidizing zones of the furnace, most of the NH_3 formed during devolatilization of black liquor droplet nitrogen is oxidized to NO or reduced to N_2. However, small amounts of ammonia (NH_3) could potentially escape unreacted. There is limited evidence suggesting NH_3 may be present in the flue gas as it exits the upper furnace (Lovblad et al. 1991). Additional study is needed on this phenomenon.

6.5.3.6 CO Emissions

Carbon monoxide is a product of incomplete combustion. Complete combustion would result in all of the organic carbon in the black liquor being converted to CO_2. CO emissions from recovery furnaces have been found to fluctuate markedly with time, and long-term mean values vary considerably from furnace to furnace. CO levels are affected by swings in liquor firing rates and liquor solids content. Empirical evidence suggests a loose positive correlation between CO and TRS emissions.

6.5.3.7 VOC Emissions

Volatile organic compounds (VOCs) are emitted in small amounts from recovery furnaces. The source of these compounds may be incomplete combustion or the liquor itself when it comes into contact with combustion gases. The most obvious contact between liquor and flue gas is in the DCE, where methanol and other volatiles can be transferred from the liquor to the flue gas. Less obvious contact occurs in the bottom of electrostatic precipitators where black liquor is used to collect the captured ash, and in furnaces that use liquor to transfer ash removed from the upper furnace areas to the salt cake mix tank. An early NCASI study (NCASI 1981) showed a) VOC emissions from kraft recovery furnaces could not be correlated to the black liquor firing rate or excess air usage, and b) VOC emissions from NDCE furnaces correlated with CO emissions, although the significance of this was not well understood.

6.5.3.8 HCl Emissions

Chlorides are present in black liquor. Sources of this chloride include wood chips, purchased caustic, purchased salt cake, mill water, and spent chlorine dioxide generator acid. When the liquor is combusted, the chlorides will partition to the smelt, to particulate matter in flue gases, and to gaseous form. Studies indicate about 75% of the chlorides will be retained in the smelt (NCASI 1994b), with most of the remainder being carried out of the furnace in particulate form, mainly as NaCl with some KCl. The particulates are captured by the ESP and DCE (if present) and returned to the liquor being fired. Anywhere from 0 to 8 % of the chlorides present in the as-fired liquor will exit as gaseous HCl. Concentrations in stack flue gases range from 0.1 to about 50 ppm (at standard conditions). For NDCE furnaces, the amount of HCl in the flue gas has been found to correlate closely with the concentration of SO_2. Furnaces with very low SO_2 emissions also have very low HCl emissions (NCASI 1994b).

6.5.3.9 PCDD/F Emissions

Due to the presence of organics and chlorides in black liquor, the possibility for formation of other chlorinated compounds in the recovery furnace has always been known to exist, although the amounts measured thus far have been extremely small. Comprehensive emission measurements have shown concentrations of gaseous chlorinated organic compounds (e.g., chloroform) to be below method detection limits in nearly all cases (NCASI 1995). EPA has focused a great deal of attention on polychlorinated dibenzo-dioxins and -furans (PCDD/Fs) over the past decade, but data on measurements provided to EPA by NCASI have shown kraft recovery furnaces to have minimal emissions of these compounds (EPA 1997).

Table 6.5.3.9-1 gives estimates of emissions from DCE and NDCE kraft recovery furnaces for TRS, THCs, SO_2, NO_x, CO, PM, acid gases H_2SO_4 and HCl, PCDD/Fs and several VOCs of significance.

Table 6.5.3.9-1 TRS, SO_2, NO_x, CO, PM, Acid Gas, PCDD/F and VOC Emissions from Kraft Recovery Furnaces
(NCASI 2003a, 2004)

	DCE Kraft Recovery Furnaces				NDCE Kraft Recovery Furnaces			
	No.	Range (lb/ton BLS)	Median	Mean	No.	Range (lb/ton BLS)	Median	Mean
Total TRS as S	18	0.055 – 0.33	0.075	0.11	13	ND – 0.17	4.7E-03	0.016
Dimethyl Disulfide	18	ND – 0.069	3.6E-03[8]	3.6E-03[8]	13	ND - 0.044	2.4E-04[8]	2.4E-04[8]
Dimethyl Sulfide	18	ND – 0.079	6.7E-04[8]	6.7E-04[8]	13	ND – 0.033	6.8E-04[8]	6.8E-04[8]
Hydrogen Sulfide	8	0.02 – 0.26	0.059	0.082	5	ND – 0.13	3.4E-03	0.016
Methyl Mercaptan	18	ND – 0.23	0.025	0.042	13	ND – 0.054	1.5E-03[8]	1.5E-03[8]
VOC[1]	12	0.01 – 1.50	0.21	0.39	19	ND – 1.07	0.09	0.15
SO_2	7	1.10 - 3.58	2.29	2.12	46	0.00 – 5.36	0.22	0.74
NO_x[2]	1	–	1.09	1.09	28	0.64 – 3.19	1.50	1.52
CO[3]	19	0.10 - 6.88	1.21	2.20	19	0.10 - 6.88	1.21	2.20
TPM[4]	23	0.07 – 2.58	0.70	0.74	20	0.02 – 3.50	0.37	0.65
CPM[5]	2	0.21 – 0.68	0.44	0.44	6	0.04 – 0.18	0.063	0.08
PM_{10}[6]	4		76.8%	75.0%	13		71.3%	67.2%
$PM_{2.5}$[6]	4		53.4%	52.9%	10		49.8%	51.0%
Acetaldehyde	9	ND – 0.071	0.019	0.023	14	ND – 0.05	4.2E-04[8]	4.2E-04[8]
Benzene	18	ND – 0.053	3.3E-03	0.01	13	ND – 0.025	6.4E-04[8]	6.4E-04[8]
Formaldehyde	7	ND – 0.0096	9.6E-04[8]	9.6E-04[8]	9	ND – 0.044	7.8E-03	6.6E-03
Hydrogen Chloride	19	ND – 0.55	0.085	0.13	27	ND – 1.23	0.055	0.25
Methanol	23	ND – 1.35	0.19	0.28	17	ND – 0.23	0.044	0.045
MEK	17	ND – 0.035	8.3E-03	9.6E-03	15	ND – 7.1E-03	9.4E-04[8]	9.4E-04[8]
Sulfuric Acid	5	ND – 0.047	0.01	0.011	6	ND – 0.071	0.02	0.028
PCDD/Fs[7]	4	0.0016 – 0.01	4.9E-03	5.4E-03	7	1.8E-05 – 0.01	2.0E-03	2.9E-03

ton BLS – ton black liquor solids; No. – number of sources tested; ND – non-detect; [1]as measured by EPA M25A; [2]a 1992 EPA Survey Questionnaire yielded average NO_x emissions from 16 DCE furnaces of about 57.4 ppm @ 8% O_2 (range 30 to 110) or about 1.20 lb/t bls (range 0.63 to 2.30); [3]same for DCE and NDCE furnaces; [4]total (filterable) particulate matter; [5]CPM (condensible particulate matter); [6]PM_{10} & $PM_{2.5}$ as determined using EPA Draft Method for determining PM_{10} & $PM_{2.5}$ - expressed as % of TPM; [7]units for PCDD/Fs are in I-TEQ ng/dscm @ 8% O_2; [8]NDs > 50%; statistically-derived average

6.5.3.10 Trace Metal Emissions

Trace metals enter the kraft recovery cycle through the wood pulped, make-up water, make-up chemicals, equipment corrosion, and fossil fuels used in recovery furnaces and lime kilns. When black liquor is burned in a recovery furnace, a small fraction of the trace metals in the liquor will be emitted through the flue gases leaving the ESP. Typically, metal purges via emissions from kraft recovery unit operations, which includes the recovery furnace, lime kiln and smelt dissolving tank, are much smaller than through pulping and recovery area solid wastes such as waste treatment system residuals, lime mud, slaker grits and dregs (Someshwar 1997). Table 6.5.3.10-1 provides a summary of recently compiled trace metals emissions data corresponding to several DCE and NDCE kraft recovery furnaces (NCASI 2003a).

It should be noted that kraft recovery furnaces have auxiliary fuel (natural gas, residual oil or distillate oil) burning capability for the purposes of furnace startup and shutdown. Auxiliary fuel may also be used to stabilize combustion when there are problems with the liquor supply and to maintain steam production if liquor firing is inadequate. Firing of auxiliary fuel can result in additional emissions of NO_x. SO_2 generated from fuel oil combustion is captured within the furnace to a significant extent by the sodium fume when the oil is burned in conjunction with black liquor or when the smelt bed is still present at the bottom of the furnace (NCASI 1990a). This capture does not take place during furnace startup on oil, since there is no smelt bed present. Oil also contains trace amounts of many metals which can contribute to emissions of metals compounds.

Table 6.5.3.10-1 Trace Metal Emissions from Kraft Recovery Furnaces
(NCASI 2003a)

	DCE Kraft Recovery Furnaces				NDCE Kraft Recovery Furnaces			
	No.	Range (lb/ton BLS)	Median	Mean	No.	Range (lb/ton BLS)	Median	Mean
TPM[1]	12	0.07 – 1.10	0.47	0.49	11	0.02 – 3.50	0.32	0.57
Sb	12	1.9E-07 – 7.0E-05	4.2E-08[2]	4.2E-08[2]	11	ND – 4.5E-06	1.5E-06[2]	1.5E-06[2]
As	12	ND – 2.1E-05	3.0E-06	5.8E-06	11	ND – 5.4E-04	1.3E-08[2]	1.3E-08[2]
Be	12	--	ND[6.0E-07]		9	5.9E-08 – 1.2E-06	1.3E-08[2]	1.3E-08[2]
Cd	12	ND – 8.1E-05	1.0E-05	1.4E-05	11	ND – 4.8E-05	7.1E-06	1.2E-05
Cr	11	4.4E-06 – 9.0E-05	1.2E-05	2.7E-05	9	2.7E-06 – 3.8E-05	1.9E-05	1.7E-05
Co	10	ND – 8.4E-06	2.8E-06	2.9E-06	11	ND – 7.7E-06	2.8E-06	3.2E-06
Pb	12	2.3E-06 – 5.3E-05	6.3E-06	1.0E-05	11	1.1E-06 – 7.0E-05	1.2E-05	2.3E-05
Mn	12	7.0E-06 – 1.0E-04	4.1E-05	4.1E-05	10	5.4E-06 – 1.7E-04	5.2E-05	5.9E-05
Hg	12	--	ND[1.3E-07]		10	ND – 7.0E-06	2.0E-06	2.0E-06
Ni	10	4.9E-06 – 3.9E-05	1.4E-05	1.8E-05	9	8.8E-06 – 6.2E-05	3.2E-05	2.8E-05
Se	12	ND – 1.8E-05	2.2E-06[2]	2.2E-06[2]	11	ND – 2.2E-04	8.0E-07[2]	8.0E-07[2]

ton BLS – ton black liquor solids; No. – number of sources tested; ND – non-detect;
[1]total (filterable) particulate matter – measured simultaneously with trace metals; [2]NDs > 50%; statistically-derived average

6.5.3.11 Solid and Liquid Discharges

Solid and liquid discharges are generally not expected from the kraft recovery furnace. A portion of the ash captured in particulate collection devices may occasionally be sent to a landfill. One reason this is done is to purge the buildup of chlorides and potassium in the liquor cycle. Typical compositions of ESP ash were given in Table 6.5.3.2-1. Besides liquor losses, no other liquid discharges are expected from the recovery furnace. For furnaces where a wet scrubber follows the ESP, liquid discharges could result from the purge in the scrubber recycle stream. For recovery furnaces that also generate electricity, wastewater streams typical of smaller industrial electricity generating plants would be present. These include ion exchange regeneration waste, boiler blowdown, and cooling system blowdown (Stultz and Kitto 1992). Ion exchange regeneration wastewater streams are normally neutralized prior to discharge.

6.5.4 Smelt Dissolving Tanks

The significant emissions from a dissolving tank vent are TRS compounds and particulate matter. Trace amounts of ammonia emissions have also been measured. VOC emissions are generally very low, unless process condensates containing significant VOCs are used to either dissolve the smelt or for scrubbing the vent gases.

6.5.4.1 TRS Emissions

TRS compounds arise principally from the sulfides present in smelt and in weak wash. H_2S is the main compound present in smelt tank vent gases, with typical concentrations measured in the range of 5 to 20 ppm. It is believed generated mainly by the shattering of smelt (Frederick, Danko, and Ayers 1996). However, if TRS- containing condensates are used in the recausticizing area, higher levels of TRS compounds could be present in the weak wash, providing greater potential for stripping of these compounds during smelt dissolving or vent gas scrubbing operations. Methyl mercaptan, dimethyl sulfide and dimethyl disulfide can be present in smelt tank vent gases if they are present in the weak wash as a result of condensate reuse.

6.5.4.2 Particulate Emissions

As with the recovery furnace, particulates are comprised of mainly sodium compounds with much lesser amounts of potassium compounds and some other trace metal compounds. The dominant compound is sodium carbonate, followed by sodium sulfate. Roughly 90% (by weight) of the particles have equivalent aerodynamic diameters under 10 μm, and 50% have diameters under 1 μm (Pinkerton and Blosser 1981; NCASI 1978a).

6.5.4.3 Other Gaseous Emissions

Volatile organic compounds such as methanol can be released from the weak wash in both the dissolving tank and the wet scrubber particulate control device. In a study of emissions from four smelt dissolving tanks, NCASI found methanol emissions were closely related to the methanol content of the weak wash used in the scrubbers (NCASI 1994c). Ammonia has been found in the smelt dissolving tank exhaust, although amounts appear to be highly variable with measured emission rates ranging from around 0.02 to 3.8 lb/ton BLS (NCASI 1999a).

Some mills have made measurements for NO_x, CO and SO_2 in smelt dissolving tank vents. However, since no combustion takes place in smelt tanks, and smelt-water explosions are not known to result in NO_x, the low level of NO_x sometimes measured is believed to be an artifact caused by oxidation of a portion of the ammonia (NH_3) emissions from such tanks to NO within the NO_x analyzer (NCASI 2003b).

10.2.2 Wood Residues

The majority of chemical wood pulp mills that debark logs on-site burn the bark and other wood residues in boilers to generate steam and power. Although smaller boiler types such as the Dutch oven and fuel cell oven are sometimes utilized, the majority of boilers with steam generation rates exceeding 100,000 lb/hr are of the spreader stoker type. At pulp and paper mills in 2004, there were 14 Dutch ovens, 13 fluidized bed boilers, 40 pulverized coal-fired boilers, and 129 spreader stokers that burned wood fuels. Most of these units routinely fired some fossil fuels as well as wood.

When wood is burned alone, the principal emissions of concern are particulates, CO and NO_x. The ash content of bark is on the order of 1 to 2%, about an order of magnitude lower than coal. Particulate emissions result from inorganic materials contained in the bark and wood itself and from carbonaceous material resulting from incomplete combustion. Like coal, uncontrolled particulate emissions will be greater where fly ash reinjection is practiced.

NO_x emissions are mainly the result of "fuel NO_x", with wood and bark nitrogen contents being in the 0.1 to 0.2% range. However, certain types of wood residues, e.g., juvenile woods, may have nitrogen contents in the 0.2 to 0.4% range. Average NO_x emissions from wood combustion in typical pulp mill boilers are lower than those from coal or residual oil combustion, and slightly higher than average NO_x emissions from natural gas burning. However, if any wood fuels containing nitrogen from other sources (e.g., sanderdust from panels bonded with urea formaldehyde resin) are burned, higher NO_x emissions can be expected.

SO_2 emissions from wood combustion are very low, since bark and other wood residues contain little sulfur (NCASI 1978). CO emissions and other products of incomplete combustion are highly variable and are a function of boiler design, operating conditions, combustion efficiency and fuel quality. HCl emissions are minimal (less than 0.001 lb/10^6 Btu heat input), unless bark from logs stored in salt water or wood material containing resins with NaCl is burned. Table 10.2.2-1 provides estimates of emissions for several criteria pollutants, selected VOCs, and greenhouse gases (CO_2, CH_4, N_20) resulting from wood residue combustion in boilers (EPA 2001). Emissions of trace metals are summarized in Table 10.2.2-2.

While wood is the sole fuel for some pulp mill boilers, most boilers burn wood in combination with one or more fossil fuels. Studies by NCASI have shown that burning wood in combination with coal or oil will result in lower SO_2 emissions than would be expected from the coal or oil combustion. This phenomenon is the result of in-furnace SO_2 capture by the alkaline wood ash (NCASI 1992). The degree of reduction is a function of the ratio of wood to coal or oil being burned. Co-firing of biomass in coal utility boilers has also been shown to lead to a reduction in NO_x emissions (NCASI 2003a). A 1% NO_x reduction is expected from baseline levels for every 1% co-firing percentage of biomass (Btu basis). The reduction in NO_x is brought about by several factors including reduced total fuel nitrogen, lower firing temperatures because of increased fuel moisture, and increased staging of the combustion process due to early volatiles burnout in the biomass fraction.

The burning of waste treatment plant (WTP) residuals in bark boilers at levels below about 10 to 15% of total heat input is not expected to lead to an increase in any of the criteria or criteria-related pollutants such as NO_x, SO_2, or VOC (NCASI 1993a), although a systematic study on this subject has not been conducted. A comparison of data on emissions of 48 organic compounds when burning wood residue and wood residue in combination with bleached kraft mill (BKM) WTP residuals (at <12 % heat input) in four wood-fired boilers showed no discernible impact on emissions of these organics when the residuals were co-fired with wood residue (NCASI 1993b). A similar comparison for metals emissions from two boilers burning wood residues and a combination of wood residues and BKM WTP residuals also showed no discernible impact due to the burning of WTP residuals (NCASI 1993b).

Table 10.2.2-1 EPA Emission Factors in lb/10^6 Btu Heat Input for Wood Combustion Boilers (EPA 2002, NCASI 2003b)

Compound	Mechanical Collector	Wet Scrubber	ESP	Electrified Gravel Bed Filter	Fabric Filter
PM	0.22 – 0.54	0.066	0.054	0.1	0.1
PM_{10}	0.2 – 0.49	0.065	0.04	0.074	0.074
$PM_{2.5}$	0.12 – 0.29	0.065	0.035	0.065	0.065
Condensible PM	0.017	0.017	0.017	0.017	0.017
	All Boiler Types except Fluidized Bed Combustors		**Fluidized Bed Combustors**		
	"Wet" Wood	"Dry" Wood			
NO_X	0.22	0.49	0.22/0.49		
CO	0.6	0.6	0.17		
Compound	**All Boiler and Control Types**				
SO_2	0.025				
HCl	0.00067				
TOC*	0.039				
VOC	0.017				
Acrolein	0.000078				
Acetaldehyde	0.00019				
Benzene	0.0033				
Formaldehyde	0.0013				
Phenol	0.000014				
Toluene	0.000029				
CO_2	195				
Methane	0.021				
N_2O	0.013				

*TOC – Total organic compounds; includes non-VOCs such as methane.

Table 10.2.2-2 Trace Metal Emissions
(EPA 1998a, 1998b, 1998c; NCASI 2003b)

	Natural Gas	No. 2 Fuel Oil	No. 6 Fuel Oil	Bit. Coal	Wood	Wood	Wood
	($lb/10^6$ scf)		($lb/10^3$ gal)	(lb/ton)	(median - $lb/10^{12}$ Btu)		
	Uncontrolled			Controlled	with MC	with WS	w ESP/FF
Sb	--	--	5.25E-03	1.8E-05	--	0.50	0.42
As	2.0E-04	4	1.32E-03	4.1E-04	1.3	3.7	0.4
Ba	4.4E-03	--	2.57E-03	--	4800	20	160
Be	<1.2E-05	3	2.78E-05	2.1E-05	0.75	0.55	0.40
Cd	1.1E-03	3	3.98E-04	5.1E-05	3.7	1.9	0.59
Cr	1.4E-03	3	8.45E-04	2.6E-04	17	6.6	0.52
Cr^{+6}	--	--	2.48E-04	7.9E-05	7.0	6.1	0.49
Co	8.4E-05	--	6.02E-03	1.0E-04	420	0.20	0.19
Pb	--	9	1.51E-03	4.2E-04	21	13	4.2
Mn	3.8E-04	6	3.00E-03	4.9E-04	1800	40	57
Hg	2.6E-04	3	1.13E-04	8.3E-05	1.6	0.66	0.62
Ni	2.1E-03	3	8.45E-02	2.8E-04	8.7	4.8	3.5
Se	<2.4E-05	15	6.83E-04	1.3E-03	5.6	2.8	3.3
Zn	2.9E-02	4	2.91E-02	--	220	280	41

MC – multiclone; WS – wet scrubber; ESP/FF – electrostatic precipitator or fabric filter

10.2.3 Other Non-Fossil Fuels

Pulp mill boilers capable of firing coal or wood often have the option to burn other solid fuels such tire chips, wastewater treatment plant residuals (sludge), rejected material from processing of old corrugated containers (OCC rejects), non-recyclable paper pellets, etc. The amount of these materials that can be burned in traditional spreader-stoker type boilers is relatively small, and co-firing them with wood and/or coal has only minimal effects on the emissions. Fluidized bed boilers, on the other hand, can accommodate much larger percentages of alternative solid fuels.

10.3 CONTROL OF STACK EMISSIONS

This section discusses the control of stack emissions from the various types of boilers and fuels discussed in Section 10.2.

10.3.1 Conventional Fossil Fuel-Fired Boilers

10.3.1.1 Natural Gas

Gas-fired boilers are usually not equipped with particulate collectors. SO_2 emissions depend on the sulfur content of the gas, which is typically negligible. NO_x emissions are dependent on the combustion temperature and the rate of cooling of the combustion products. There are several combustion modification techniques available to reduce the amount of NO_x formed in natural gas-fired boilers and turbines. The two most prevalent ones are flue gas recirculation (FGR) and low-NOx burners. FGR

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Florida Department of Environmental Protection

Memorandum

To: Trina Vielhauer, Bureau of Air Regulation

Through: Jeff Koerner, New Source Review Section

From: Bruce Mitchell, New Source Review Section

Date: June 13, 2008

Subject: 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:

- 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 12 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

P.E. CERTIFICATION STATEMENT

PERMITTEE

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

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

PROJECT DESCRIPTION

Buckeye Florida, Limited Partnership operates an existing dissolving grade Kraft process pulp mill in Perry located at One Buckeye Drive in Taylor County, Florida. The plant 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 12 megawatt condensing steam turbine-electrical generator set; and miscellaneous common system changes including piping, ductwork, pumps, tanks, etc.

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.

I HEREBY CERTIFY *that the air pollution control engineering features described in the above referenced application and subject to the proposed permit conditions provide reasonable assurance of compliance with applicable provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Chapters 62-4 and 62-204 through 62-297. However, I have not evaluated and I do not certify any other aspects of the proposal (including, but not limited to, the electrical, mechanical, structural, hydrological, geological, and meteorological features).*

Jeffery J. Koerner

Jeffery F. Koerner, P.E.
Registration Number 49441

6-13-08
(Date)

Florida Department of Environmental Protection

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

June 13, 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: 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. Enclosed are the following 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

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 6/13/08 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. Amy
(Clerk)

6/13/08
(Date)

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

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 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 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.

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 12 megawatt condensing steam turbine-electrical generator set; and miscellaneous common system changes including piping, ductwork, pumps, tanks, etc.

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 ($\mu g/m^3$)	Increment Consumed ($\mu g/m^3$)	Increment Consumed 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.

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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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 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.

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 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 this Public Notice or receipt of a written notice, 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 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

June 13, 2008

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 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	548 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

- 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 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 12 MW condensing steam turbine-electrical generator will be installed 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 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.

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

Discussion

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.

Available Technologies for the Control of NOx Emissions

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.

<u>Applicant's Proposal</u>

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 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

[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

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.

Department's Review

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.

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:

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

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 $\leq$ 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 $\leq$ 0.044 grains per dscf @ 8% oxygen pursuant to NSPS Subpart BB; and
- PM $\leq$ 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.
- Once the ESP is placed in service during startup of a recovery boiler, visible emissions shall not exceed 20% opacity based on a 6-minute average as determined by COMS and EPA Method 9.

Compliance with the PM standard shall be demonstrated by conducting initial and annual stack tests. Compliance with the opacity standard shall be demonstrated by a certified COMS and EPA Method 9.

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 12 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 12 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 12 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

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

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.

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 ($\mu g/m^3$)**	**Significant Impact Level ($\mu g/m^3$)**	**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 (μg/m^3)**	**Significant Impact Level (μg/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 (μg/m^3)**	**Allowable Increment (μg/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 (μg/m^3)	Ambient Background Concentration (μg/m^3)	Total Impact (μg/m^3)	AAQS (μg/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.

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 12 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 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. 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 12 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. 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 fuel oil will be fired. The maximum 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	12 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.]

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 F 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 548 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. [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: Once the ESP is placed in service during startup of a recovery boiler, visible emissions shall not exceed 20% opacity based on a 6-minute average as determined by the existing COMS and EPA Method 9. The new standard becomes effective after completing shakedown of each boiler, but no later than 60 calendar days following first fire after completing the conversion. Excess opacity resulting from malfunction of the ESP shall be permitted providing, (1) best operational practices to minimize emissions are adhered to, and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24-hour period. [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 E (Standard Continuous 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
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 1^{st} to September 30^{th}), 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*: 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	12 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 7200 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 12 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 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 12 MW condensing turbine-electrical generator set. Existing equipment may satisfy this requirement. [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 12 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 12 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

8. Monthly Fuel Records: After completing construction of the new 12 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. After a delivery of No. 6 residual oil, the permittee shall sufficiently mix the oil within the tank. A sample shall be taken and analyzed for the sulfur content and heating value. This shall be the fuel sulfur content used for emissions calculations until a subsequent delivery. Incidental amounts of facility-generated on-specification used oil may be added to the residual oil tank without requiring a new fuel sulfur analysis.

   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

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.]

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 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 12 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. 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
PM	0.030 grains/dscf @ 8% O_2 and 31.6 lb/hour	Electrostatic Precipitator	EPA Method 5

Pollutant	BACT Standards	Control Technology Basis	Monitoring
			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. *{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]

TRAcking Page

BEST AVAILABLE COPY

WRITTEN NOTICE OF INTENT TO ISSUE AIR PERMIT

Mediation: Mediation is not available in this proceeding.

1230001-023-AC

Buckeye Florida PSD-FL-397

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 6/13/08 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.

(Clerk) 6/13/08 (Date)

Harvey, Mary

From: Howard Drew [Howard_Drew@BKITECH.COM]
Sent: Friday, June 13, 2008 3:05 PM
To: Harvey, Mary
Cc: Dave Weeden; Earle Greene; Ray Andreu; Ray Perry; Chip Aiken; Randy Dees; Don Asmus
Subject: RE: Buckeye Florida - 1230001-023-AC-DRAFT - PSD-FL-397
Importance: High

Ms. Harvey,
I received this document. Thank you very much for your attention to this matter.
Sincerely,

Howard Drew
Site manager

From: Harvey, Mary [mailto:Mary.Harvey@dep.state.fl.us]
Sent: Friday, June 13, 2008 1:15 PM
To: Howard Drew; Dave Weeden; Ray Perry; Mr. David A. Buff, P.E., Golder Associates, Inc.; Kirts, Christopher; Ms. Kathleen Forney, U.S. EPA, Region 4; Mr. Dee Morse, National Park Service
Cc: Mitchell, Bruce; Walker, Elizabeth (AIR); Gibson, Victoria
Subject: Buckeye Florida - 1230001-023-AC-DRAFT - PSD-FL-397

Dear Sir/Madam:

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).

The document(s) may require immediate action within a specified time frame. Please open and review the document(s) as soon as possible.

The document is in Adobe Portable Document Format (pdf). Adobe Acrobat Reader can be downloaded for free at the following internet site: http://www.adobe.com/products/acrobat/readstep.html.

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. Please advise this office of any changes to your e-mail address or that of the Engineer-of-Record.

Thank you,

DEP, Bureau of Air Regulation

Harvey, Mary

From: Kirts, Christopher
To: Harvey, Mary
Sent: Monday, June 23, 2008 8:13 AM
Subject: Read: FW: Buckeye Florida - 1230001-023-AC-DRAFT - PSD-FL-397

Your message

To: 'Mr. David Weeden, Buckeye Florida, Limited Partnership'; 'Mr. Ray Perry, Buckeye Florida, Limited Partnership'; 'Mr. David A. Buff, P.E., Golder Associates, Inc.'; Kirts, Christopher; 'Ms. Kathleen Forney, U.S. EPA, Region 4'; 'Mr. Dee Morse, National Park Service'
Subject: FW: Buckeye Florida - 1230001-023-AC-DRAFT - PSD-FL-397
Sent: 6/20/2008 3:37 PM

was read on 6/23/2008 8:13 AM.

Harvey, Mary

From: Ray Perry [Ray_Perry@BKITECH.COM]
To: undisclosed-recipients
Sent: Saturday, June 21, 2008 7:36 AM
Subject: Read: Buckeye Florida - 1230001-023-AC-DRAFT - PSD-FL-397

Your message

To: Ray_Perry@BKITECH.COM
Subject:

was read on 6/21/2008 7:36 AM.

Harvey, Mary

From: Buff, Dave [DBuff@GOLDER.com]
To: undisclosed-recipients
Sent: Friday, June 20, 2008 5:30 PM
Subject: Read: Buckeye Florida - 1230001-023-AC-DRAFT - PSD-FL-397

Your message

To: DBuff@GOLDER.com
Subject:

was read on 6/20/2008 5:30 PM.

Harvey, Mary

From: Forney.Kathleen@epamail.epa.gov
Sent: Friday, June 20, 2008 4:48 PM
To: Harvey, Mary
Subject: Re: FW: Buckeye Florida - 1230001-023-AC-DRAFT - PSD-FL-397

thanks

Katy R. Forney
Air Permits Section
EPA - Region 4
61 Forsyth St., SW
Atlanta, GA 30303

Phone: 404-562-9130
Fax: 404-562-9019

"Harvey, Mary" <Mary.Harvey@dep.state.fl.us>

06/13/2008 01:16 PM

To: Kathleen Forney/R4/USEPA/US@EPA
cc:
Subject: FW: Buckeye Florida - 1230001-023-AC-DRAFT - PSD-FL-397

From: Harvey, Mary
Sent: Friday, June 13, 2008 1:15 PM
To: 'Mr. Howard Drew, Buckeye Florida, Limited Partnership'; 'Mr. David Weeden, Buckeye Florida, Limited Partnership'; 'Mr. Ray Perry, Buckeye Florida, Limited Partnership'; 'Mr. David A. Buff, P.E., Golder Associates, Inc.'; Kirts, Christopher; 'Ms. Kathleen Forney, U.S. EPA, Region 4'; 'Mr. Dee Morse, National Park Service'
Cc: Mitchell, Bruce; Walker, Elizabeth (AIR); Gibson, Victoria
Subject: Buckeye Florida - 1230001-023-AC-DRAFT - PSD-FL-397

Dear Sir/Madam:

Harvey, Mary

From: Dee_Morse@nps.gov
Sent: Monday, June 23, 2008 11:30 AM
To: Harvey, Mary
Subject: FW: Buckeye Florida - 1230001-023-AC-DRAFT - PSD-FL-397

Return Receipt

Your document:	FW: Buckeye Florida - 1230001-023-AC-DRAFT - PSD-FL-397
was received by:	Dee Morse/DENVER/NPS
at:	06/23/2008 09:27:57 AM MDT

Harvey, Mary

From: Dave Weeden [Dave_Weeden@bkitech.com]
Sent: Monday, June 23, 2008 10:09 AM
To: Harvey, Mary
Subject: RE: Buckeye Florida - 1230001-023-AC-DRAFT - PSD-FL-397

Mary,

Sorry if you have not already received this acknowledgement. We did receive the email.

Dave

Dave Weeden
Environmental Program Manager
Buckeye Technologies, Inc.

(850) 584-1398

From: Harvey, Mary [mailto:Mary.Harvey@dep.state.fl.us]
Sent: Friday, June 20, 2008 3:37 PM
To: Dave Weeden; Ray Perry; Mr. David A. Buff, P.E., Golder Associates, Inc.; Kirts, Christopher; Ms. Kathleen Forney, U.S. EPA, Region 4; Mr. Dee Morse, National Park Service
Subject: FW: Buckeye Florida - 1230001-023-AC-DRAFT - PSD-FL-397

Good Afternoon:

This permit email out on Friday, June 13th. Please email me your read receipt if you have received this permit. We need the read receipt so that we can verify that the permit was received.

Thanks again,
Mary Harvey

From: Harvey, Mary
Sent: Friday, June 13, 2008 1:15 PM
To: 'Mr. Howard Drew, Buckeye Florida, Limited Partnership'; 'Mr. David Weeden, Buckeye Florida, Limited Partnership'; 'Mr. Ray Perry, Buckeye Florida, Limited Partnership'; 'Mr. David A. Buff, P.E., Golder Associates, Inc.'; Kirts, Christopher; 'Ms. Kathleen Forney, U.S. EPA, Region 4'; 'Mr. Dee Morse, National Park Service'
Cc: Mitchell, Bruce; Walker, Elizabeth (AIR); Gibson, Victoria
Subject: Buckeye Florida - 1230001-023-AC-DRAFT - PSD-FL-397

Dear Sir/Madam:

Harvey, Mary

From: Dave Weeden [Dave_Weeden@bkitech.com]
To: undisclosed-recipients
Sent: Monday, June 23, 2008 10:08 AM
Subject: Read: Buckeye Florida - 1230001-023-AC-DRAFT - PSD-FL-397

Your message

To: Dave_Weeden@bkitech.com
Subject:

was read on 6/23/2008 10:08 AM.

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 ($\mu g/m^3$)	Increment Consumed ($\mu g/m^3$)	Increment Consumed 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.

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 the 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 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.

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 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 this Public Notice or receipt of a written notice, 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 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

Discussion

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.

Available Technologies for the Control of NOx Emissions

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.

<u>Applicant's Proposal</u>

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.

Department's Review

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).

<u>Department's Review</u>

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.

- <u>Phase I</u>: 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.
- <u>Phase II</u>: 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 (μg/m^3)**	**De Minimis Concentration (μg/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 ($\mu g/m^3$)	Significant Impact Level ($\mu g/m^3$)	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.

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(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.]

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. <u>CEMS for Reporting Annual Emissions</u>: 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.

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

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.]

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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 CFR 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. <u>Generator</u>: The on-specification used oil fired shall be generated at this facility.

3. <u>Sampling and Analysis</u>:

   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. <u>Used Oil Recordkeeping Required</u>: 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. <u>Used Oil Reporting Required</u>: 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
'Forney.Kathleen@epamail.epa.gov'		
'dee_morse@nps.gov'		
Mitchell, Bruce	Delivered: 7/7/2008 6:40 PM	

BUCKEYE

ONE BUCKEY DRIVE
PERRY, FLORIDA 32348-7702

RECEIVED

JUL 23 2008

BUREAU OF AIR REGULATION

July 15, 2008

Bruce Mitchell
Bureau of Air Regulation
Florida Department of Environmental Protection
2600 Blair Stone Road, MS #5505
Tallahassee, FL 32399-2400

Re: Taylor County - Air Permitting
Buckeye Florida Limited Partnership
Energy Independence Project – Public Notice
Project No. 1230001-023-AC

Dear Mr. Mitchell,

Attached is an affidavit from Mr. Donald D. Lincoln, publisher of the Perry News-Herald/Taco Times, confirming that the "Intent to Issue" for the above referenced project was published on Friday, July 11, 2008.

If you have any questions, please contact me at (850) 584-1398.

Sincerely,

Buckeye Florida Limited Partnership

David C. Weeden
Environmental Program Manager

BEST AVAILABLE COPY

PERRY NEWS-HERALD/TACO TIMES

Published Weekly in the City of Perry
County of Taylor, State of Florida

AFFIDAVIT OF PUBLICATION

Before me, the undersigned authority personally appeared DONALD D. LINCOLN, who on oath says that he is the PUBLISHER of the Perry News-Herald/ Taco Times, both weekly newspapers published in Perry, Taylor County, Florida, that the attached copy of advertisement in re:

Intent to Issue Air Permit

was published in said newspaper in the issues of:

July 11, 2008

Affiant says further that the said, newspapers published at Perry in said Taylor County, Florida, each week; has been entered as second class mail matter at the Post Office in Perry, Florida, in said Taylor County, Florida for a period of one year next proceeding the first publication of the attached copy of notice to appear: and affiant further says that he has neither paid nor promised any person, firm or corporation any discount, rebate, commission or refund for the purpose of securing this advertisement for publication in said newspaper.

Donald D. Lincoln

Donald D. Lincoln, Publisher

Sworn to and subscribed
before me this
11 day of July 2008

Debra M. Carlton
Notary Public

DEBRA M. CARLTON
MY COMMISSION # DD 694950
EXPIRES: August 13, 2011
Bonded Thru Notary Public Underwriters

LEGALS **LEGALS**

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 III 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 (N02) consumed by all sources in the area, including this project.

Summary of PSD Class II Increment Analysis

Pollutant	Averaging Time	Allowable Increment (ug/m^3)	Increment Consumed (ug/m^3)	Increment Consumed 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.

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 the 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

Notary Public

BEST AVAILABLE COPY

DEBRA M. CARLTON
MY COMMISSION # DD 694950
EXPIRES: August 13, 2011
Bonded Thru Notary Public Underwriters

issued for this project on June 13,2005. 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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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 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.

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 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 this Public Notice or receipt of a written notice, 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 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.

PERRY NEWS-HERALD/TACO TIMES
Published Weekly in the City of Perry
County of Taylor, State of Florida

AFFIDAVIT OF PUBLICATION

Before me, the undersigned authority personally appeared DONALD D. LINCOLN, who on oath says that he is the PUBLISHER of the Perry News-Herald/ Taco Times, both weekly newspapers published in Perry, Taylor County, Florida, that the attached copy of advertisement in re:

Intent to Issue Air Permit

was published in said newspaper in the issues of:

July 11, 2008

Affiant says further that the said, newspapers published at Perry in said Taylor County, Florida, each week; has been entered as second class mail matter at the Post Office in Perry, Florida, in said Taylor County, Florida for a period of one year next proceeding the first publication of the attached copy of notice to appear: and affiant further says that he has neither paid nor promised any person, firm or corporation any discount, rebate, commission or refund for the purpose of securing this advertisement for publication in said newspaper.

Donald D. Lincoln

Donald D. Lincoln, Publisher

Sworn to and subscribed before me this 11 day of July 2008

Debra M. Carlton
Notary Public

DEBRA M. CARLTON
MY COMMISSION # DD 694950
EXPIRES: August 13, 2011
Bonded Thru Notary Public Underwriters

LEGALS **LEGALS**

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 of 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 III 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 (N02) consumed by all sources in the area, including this project.

Summary of PSD Class II Increment Analysis

Pollutant	Averaging Time	Allowable Increment (ug/m^3)	Increment Consumed (ug/m^3)	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.

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 the 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.

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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.

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Mediation: Mediation is not available in this proceeding.

7/11

File Copy

Buckeye Florida LP *1230001-023-AC* *OGC # 08-1743*

(Bruce M)

2008								
23-Jun		OGC received 1st request for an extension of time						
2-Jul		Trina asked Ronni to hold this request unitl we withdraw the old permit and						
		issue a new permit						
7-Jul		Department issued the revised draft						
8-Jul		Ronni issued the closure memo on this case						
			CASE CLOSED					

Florida Department of Environmental Protection
Office of General Counsel

Memo

To: Trina Vielhauer, and OGC File

From: Ronni Moore, Assistant General Counsel

Date: July 8, 2008

Re: Buckeye Florida, L.P., vs. DEP; DEP Permit No. PSD-FL-397; OGC No. 08-1743

On June 13, 2008, the Department issued a notice of intent to issue air permit no. PSD-FL-397 to Buckeye Florida, L.P., (Buckeye). Thereafter, Buckeye timely requested an extension of time to file a petition for administrative hearing on the draft permit. Before the Department issued an order granting Buckeye's time extension, the Department significantly changed the draft permit and issued Buckeye a revised draft permit on July 7, 2008. There being no further matters to consider, the Department's file in this matter is closed.

Gibson, Victoria

From:	Vielhauer, Trina
Sent:	Tuesday, July 08, 2008 3:59 PM
To:	Gibson, Victoria
Subject:	FW: Buckeye Florida OGC # 08-1743 re: MEMO CLOSING FILE
Attachments:	081743 7-8-08.pdf

From: Swango, Katie
Sent: Tuesday, July 08, 2008 3:13 PM
To: Vielhauer, Trina
Cc: Moore, Ronni
Subject: Buckeye Florida OGC # 08-1743 re: MEMO CLOSING FILE

Please find attached the PDF version of the memo closing file prepared by Ronni Moore. Please let me know if you have a problem opening or viewing the above attachment and I will send you a hard copy as soon as possible.

Thanks

Katie Marie Swango
Administrative Assistant for
Rebecca Robinette, Chris Mcguire, Augusta Posner,
Ronni Moore, Lisa Duchene, Pat Comer, & Holly Cauley

Gibson, Victoria

From: Gibson, Victoria
Sent: Wednesday, July 02, 2008 3:55 PM
To: Moore, Ronni; Swango, Katie
Cc: Vielhauer, Trina; Mitchell, Bruce; Koerner, Jeff
Subject: FW: Buckeye Florida -- 1230001-023-AC

Hi Ronni,

Trina needs to have this case put on hold since we will be withdrawing the old permit and issuing a new permit soon.

Thank you and have a great weekend.

Vickie

Victoria Gibson, Administrative Secretary for
Trina Vielhauer, Chief
Bureau of Air Regulation
Division of Air Resource Management
victoria.gibson@dep.state.fl.us
850-921-9504 fax 850-921-9533

From: Vielhauer, Trina
Sent: Wednesday, July 02, 2008 3:47 PM
To: Gibson, Victoria
Subject: RE: Buckeye Florida -- 1230001-023-AC

sure

From: Gibson, Victoria
Sent: Wednesday, July 02, 2008 3:32 PM
To: Vielhauer, Trina
Subject: RE: Buckeye Florida -- 1230001-023-AC

Should I send you comment to Ronni then and ask her just to place the request on hold?

From: Vielhauer, Trina
Sent: Wednesday, July 02, 2008 3:31 PM
To: Gibson, Victoria
Subject: RE: Buckeye Florida -- 1230001-023-AC

We will be issuing a new permit soon so I'd say we can either grant it or sit on it (it will become moot because we will withdraw that old permit and reissue a new one in probably a week or so.)

From: Gibson, Victoria
Sent: Wednesday, July 02, 2008 3:28 PM
To: Vielhauer, Trina
Subject: Buckeye Florida -- 1230001-023-AC

Hi,

Where are we with their request for an extension of time through 7/23 or so?

Vickie

Victoria Gibson, Administrative Secretary for
Trina Vielhauer, Chief
Bureau of Air Regulation
Division of Air Resource Management
victoria.gibson@dep.state.fl.us
850-921-9504 fax 850-921-9533

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

BUCKEYE FLORIDA, L.P.,

Petitioner,

v.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION,

Respondent.
_______________________________________/

OGC CASE #
Draft Air Permit No. PSD-FL-397
Project No. 1230001-023-AC

MOTION FOR EXTENSION OF TIME

Buckeye Florida Limited ("Buckeye"), by and through its undersigned counsel, hereby requests a 30-day extension of time in which to file a Petition for Administrative Proceeding on Draft Air Permit No.: PSD-FL-397; Project No.: 1230001-023-AC, received by electronic transmission from DEP on June 16, 2008.

Buckeye also requests an extension of the requirement for public notice to be published. It requests that the public notice publishing requirement be extended until after the department determines whether the draft permit may be amended to reflect the comments which Buckeye intends to furnish.

The grounds for the motion are as follows:

1. A preliminary review of the draft permit revealed several potential issues that require further comment and discussion with the department.

2. In addition, time is required by the Department to develop a revised permit consolidating and incorporating comments as it determines appropriate. This informal process is more efficient in terms of both department and Buckeye staff time than resolution through the

filing of a Petition for Administrative Hearing.

3. Buckeye desires to preserve its right to hearing should the requested revisions not be incorporated.

4. In a meeting with the Department Trina Vielhauer indicated DEP did not object to this extension.

6. This Motion is filed timely.

WHEREFORE, Buckeye respectfully requests that the time within which to file a petition for administrative proceeding and public notice be extended by 30 days. Buckeye specifically wishes to preserve its right to hearing and should this request for extension of time be denied, requests that this be treated as a Petition for Formal Administrative Proceeding.

<u>CERTIFICATE OF SERVICE</u>

I HEREBY CERTIFY that the foregoing Motion for Extension of Time has been filed with Lea Crandall, Agency Clerk, Department of Environmental Protection, 3900 Commonwealth Boulevard, Tallahassee, Florida 32399; Trina Vielhauer, Chief, Division of Air Resource Management, 2600 Blair Stone Road MS 5505, Tallahassee, Florida 32399-2400; by electronic transmission this 23rd day of June, 2008.

Respectfully submitted,

OERTEL, FERNANDEZ, COLE & BRYANT, P.A.
Post Office Box 1110
Tallahassee, Florida 32302-1110
850-521-0700; Fax: 850-521-0720

Terry Cole

Terry Cole
Florida Bar ID No. 133550
Attorneys for BUCKEYE FLORIDA, L.P.

Gibson, Victoria

From: Crandall, Lea
Sent: Monday, June 23, 2008 12:10 PM
To: Chisolm, Jack; Brown, Fawn; Gibson, Victoria; Mitchell, Bruce
Subject: Request for Extension of Time rec'd. - 1230001-023 - Buckeye Florida, LP.

Attachments: 2075 Buckeye Motion for Extension of Time 023AC-PSD-FL-397.pdf

2075 Buckeye Motion for Exten...

FYI, the attached Request for Extension of Time was filed today re: 1230001-023 - Buckeye Florida, LP.

Thanks,
Lea

Lea Crandall
Agency Clerk
Office of General Counsel
3900 Commonwealth Boulevard, MS 35
Tallahassee, FL 32399-3000
Phone: (850) 245-2212
Fax: (850) 245-2303
FLORIDA DISCOUNT CARD: More than 3,000 retail pharmacies in Florida are now a part of the Florida Discount Drug Card program. See www.FloridaDiscountDrugCard.com for more info or call toll-free, 1-866-341-8894.

-----Original Message-----
From: Becki Frazier [mailto:bfrazier@ohfc.com]
Sent: Monday, June 23, 2008 10:58 AM
To: Crandall, Lea
Cc: Vielhauer, Trina; Dave Weeden; ray_perry@bkitech.com; Ray Andreu; Terry Cole
Subject: Buckeye Filing for today

Good morning Lea. Attached is a motion for extension of time from Buckeye Florida, L.P. for filing today. Thanks so much and I hope you have a wonderful Monday.

Becki Frazier
Legal Assistant to
Terry Cole and Scott Foltz
Oertel, Fernandez, Cole & Bryant, P.A.
301 S. Bronough St., Suite 500
P.O. Box 1110 (32302-1110)
Tallahassee, Florida 32301
Phone: (850) 521-0700
Fax: (850) 521-0720
www.ohfc.com
bfrazier@ohfc.com

"Live Simply, Love Generously, Care Deeply, Speak Kindly, Leave The Rest To God"

Legal Case Tracking - Chronology of Activities

07/09/2008 14:34:20

Chronology of Activities

OGC Number 08 1743 62 AC District NORTHEAST County TAYLOR

Style of Case BUCKEYE FLORIDA, L.P. VS. DEP

Program Area AIR CONSTRUCT Mode PERMITTING

Lead Attorney RONNI L MOORE Status CLOSED

Forum Name Forum Case Number

Permit Appl 1230001-023-AC Final Order Number

Date *	Code	Activity Description
06/13/2008		INTENT TO ISSUE PERMIT SENT OUT
06/23/2008	AA	ASSIGNED TO LEAD ATTORNEY JACK J CHISOLM
06/23/2008	ACO	ADMIN. CASE OPENED IN OGC
06/23/2008	REX1	RECEIVED FIRST REQUEST FOR EXTENSION OF TIME
07/07/2008		NEW INTENT TO ISSUE SENT OUT - PRIOR INTENT RESCINDED.
07/08/2008		MEMO CLOSING FILE SENT OUT
07/08/2008	AR	RE-ASSIGNED TO LEAD ATTORNEY RONNI L MOORE
07/09/2008	CC	CASE CLOSED IN OGC
07/09/2008		TO BE ARCHIVED PER RONNI MOORE