Memorandum

Florida Department of Environmental Protection

TO: Trina Vielhauer, Chief - Bureau of Air Regulation

THROUGH: Jeff Koerner, New Source Review Section

FROM: Bruce Mitchell

DATE: May 9, 2008

SUBJECT: Draft Air Permit No. PSD-FL-393
Project No. 1070005-045-AC
Georgia-Pacific Consumer Operations LLC
Modifications to the No. 4 Combination Boiler

Attached for your review are the following items:

- Intent to Issue Permit and Public Notice Package;
- Technical Evaluation and Preliminary Determination (with BACT Determination);
- Draft PSD Permit; and
- P.E. Certification

The P.E. certification briefly summarizes the proposed permit project. The Technical Evaluation and Preliminary Determination provide a detailed description of the project, rationale, and conclusion. I recommend your approval of the attached Draft Permit for this project.

Attachments

WRITTEN NOTICE OF INTENT TO ISSUE AIR PERMIT

In the Matter of an
Application for Air Permit by:

Georgia-Pacific Consumer Operations LLC
P.O. Box 919
Palatka, Florida 32178-0919

Authorized Representative:
Mr. Keith Wahoske, Vice President of Palatka Operations

Draft Air Permit No. PSD-FL-393
Project No. 1070005-045-AC
Palatka Mill
Modification of the No. 4 Combination Boiler
Putnam County, Florida

Facility Location: Georgia-Pacific Consumer Operations LLC operates an existing paper and pulp mill in Palatka located North of CR 216 and West of US 17 in Putnam County, Florida.

Project: The applicant proposes to modify the No. 4 Combination Boiler. 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, nitrogen oxides, particulate matter with an aerodynamic diameter of 10 microns or less and volatile organic compounds in accordance with Rule 62-212.400, Florida Administrative Code (F.A.C.). The project is subject to major source preconstruction review. Details of the project are provided in the attached Technical Evaluation and Preliminary Determination.

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

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 9, 2008

Electronically Sent – Received Receipt Requested

Mr. Keith Wahoske
Vice President – Palatka Operations
Georgia-Pacific Consumer Operations LLC
Palatka Mill
P.O. Box 919
Palatka, Florida 32178-0919

Re: Draft Air Permit No. PSD-FL-393
Project No. 1070005-045-AC
Georgia-Pacific Consumer Operations LLC – Palatka Mill
Request to Modify the No. 4 Combination Boiler

Dear Mr. Wahoske:

On June 18, 2006, Georgia-Pacific Consumer Operations LLC submitted an application to modify the No. 4 Combination Boiler at the existing Palatka Mill, which is located in Putnam County North of CR 216 and West of US 17 in Palatka, Florida. Enclosed are the following documents: Technical Evaluation and Preliminary Determination, Draft Permit, 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 Vielhauer

Trina Vielhauer, Chief
Bureau of Air Regulation

Enclosures

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 fourteen (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 fourteen (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 fourteen (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

WRITTEN NOTICE OF INTENT TO ISSUE AIR PERMIT

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 5/9/08 to the persons listed below.

Mr. Keith Wahoske, Georgia-Pacific Consumer Operations LLC (keith.wahoske@gapac.com)
Mr. Mike Curtis, Georgia-Pacific Consumer Operations LLC (michael.curtis@gapac.com)
Mr. Mark Aguilar, P.E., Georgia-Pacific Consumer Operations LLC (mjaguila@gapac.com)
Mr. Wayne Galler, Georgia-Pacific Consumer Operations LLC (wjgaller@gapac.com)
Mr. David Buff, P.E., Golder Associates, Inc. (dbuff@golder.com)
Mr. Chris Kirts, Northeast District Office (Christopher.Kirts@dep.stste.fl.us)
Ms. Katy 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) 5/9/08 (Date)

PUBLIC NOTICE OF INTENT TO ISSUE AIR PERMIT

Florida Department of Environmental Protection
Bureau of Air Regulation
Project No. 1070005-045-AC, Draft Air Permit No. PSD-FL-393
Georgia-Pacific Consumer Operations LLC – Palatka Mill
Putnam County, Florida

Applicant: The applicant for this project is the Georgia-Pacific Consumer Operations LLC. The applicant's authorized representative and mailing address is: Mr. Keith Wahoske, Vice President of Palatka Operations, Georgia-Pacific Consumer Operations LLC, P.O. Box 919, Palatka, Florida 32178-0919.

Facility Location: Georgia-Pacific Consumer Operations LLC operates an existing paper and pulp mill in Palatka located North of CR 216 and West of US 17 in Putnam County, Florida.

Project: The applicant proposes to modify the No. 4 Combination Boiler in two phases. The initial phase includes the following changes: upgrades to the bark/wood delivery system with new air swept bark conveyors and feed bin to increase bark/wood firing rate; increase the maximum hourly heat input rate; installation of a new overfire air (OFA) system; installation of a new mechanical collector to replace the existing multiclone pre-cleaner; installation of a bottom ash handling system; modification of ductwork to use the existing multiclone/electrostatic precipitator (ESP)/stack from the No. 5 Power Boiler (which has been converted to natural gas) to serve the No. 4 Combination Boiler in parallel with the existing multiclone/ESP/stack; and modification of ductwork to introduce the dilute non-condensible gases into the new OFA system. The second phase will convert the supplemental residual oil firing system for the No. 4 Combination Boiler to natural gas and permanently discontinue use of residual oil. Implementing this phase is dependent on obtaining additional pipeline capacity from the natural gas vendor, the Florida Gas Transmission Company, which may take approximately 2 to 3 years depending on the siting process for new pipelines as well as construction.

Potential emissions from the No. 4 Combination Boiler may increase by the following amounts: 455 tons/year of carbon monoxide (CO), 180 tons/year of nitrogen oxides (NO_X), 1 ton/year of particulate matter with an aerodynamic diameter of 10 microns or less (PM_{10}), and 20 tons/year of volatile organic compounds (VOC). Conversion from supplemental residual fuel oil to natural gas will result in a potential reduction of more than 3800 tons/year of sulfur dioxide and 163 tons per year of sulfuric acid mist. 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 CO, NO_X, PM_{10} and VOC in accordance with Rule 62-212.400, Florida Administrative Code (F.A.C.).

The draft permit establishes emissions standards for these pollutants based on the Best Available Control Technologies (BACT) as determined by the Department. Particulate matter emissions will be controlled with new mechanical collectors and an improved ESP system. Emissions of CO, NO_X and VOC will be controlled by improving overall combustion and staging combustion with the upgraded OFA system. Low-NO_X burners will be installed to further reduce NO_X emissions when firing natural gas. Continuous emissions monitors are required for CO and NO_X to demonstrate compliance, which will also provide feedback to the control system and operators. If unable to achieve the new NO_X BACT standard with the new OFA system alone, the permit requires installation of additional NO_X control equipment, such as selective non-catalytic reduction.

An air quality impact analysis was conducted. Emissions from the facility will not significantly contribute to or cause a violation of any state or federal ambient air quality standards. The maximum predicted PSD Class II increments of nitrogen dioxide (NO_2) and PM_{10} consumed by all sources in the area, including this project, are summarized in the following table.

PSD Class II Increment Analysis

Pollutant	Consumed ($\mu g/m^3$)	Allowable ($\mu g/m^3$)	Percent Consumed
PM_{10}			
24-hour average	22	30	73
Annual average	0	17	0
NO_2			
Annual average	3	25	12

Emissions of NO_2 and PM_{10} from the project have no significant impact on any of the affected PSD Class I areas (Okefenokee, Chassahowitzka and Wolf Island National Wilderness Areas).

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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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.

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Mediation: Mediation is not available in this proceeding.

(Public Notice to be Published in the Newspaper)

TECHNICAL EVALUATION

AND

PRELIMINARY DETERMINATION

PROJECT

Draft Air Permit No. PSD-FL-393
Project No. 1070005-045-AC

Georgia-Pacific Palatka Mill
Modification of the No. 4 Combination Boiler

COUNTY

Putnam County, Florida

APPLICANT

Georgia-Pacific Consumer Operations LLC
P.O. Box 919
Palatka, Florida 32178-0919

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, FL 32399-2400

May 9, 2008

1. GENERAL PROJECT INFORMATION

Application for PSD Air Construction Permit

This project is subject to the applicable environmental laws specified in Section 403 of the Florida Statutes (F.S.), which authorize the Department of Environmental Protection (Department) to establish rules and regulations regarding air quality as part of the Florida Administrative Code (F.A.C.). Specifically, an application was submitted for preconstruction review subject to the requirements for the Prevention of Significant Deterioration (PSD) of Air Quality in accordance with Rule 62-212.400, F.A.C.

Facility Description and Location

Georgia-Pacific operates an existing Kraft paper and pulp mill (SIC Nos. 2611 and 2621) in Putnam County, north of County Road 216 and west of U.S. Highway 17 in Palatka, Florida. The UTM map coordinates are: Zone 17, 434.0 km East, and 3283.4 km North. 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 furnace 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 are met by the combination, power and recovery boilers, which burn a variety of fuels including carbonaceous, BLS, fuel oil and natural gas.

Facility Regulatory Categories

- The facility is a major source of hazardous air pollutants (HAP).
- The facility operates 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 62-213, F.A.C.
- The facility is a major stationary source in accordance with Rule 62-212.400(PSD), F.A.C.

Regulated Pollutants

Criteria Pollutants: Emissions units may emit one or more of the following criteria air pollutants that are subject to PSD preconstruction review: carbon monoxide (CO), lead (Pb), nitrogen oxides (NO_X), ozone (volatile organic compounds (VOC) as surrogate), particulate matter (PM), particulate matter with a mean particle diameter of 10 microns or less (PM_{10}) and sulfur dioxide (SO_2).

Other PSD-Regulated Pollutants: In addition to the above criteria air pollutants, emissions units may emit one or more of the following pollutants that are also subject to the PSD preconstruction review: fluorides (Fl), hydrogen sulfide (H_2S), mercury (Hg), regulated sulfur compounds (RSC), sulfuric acid mist (SAM) and total reduced sulfur compounds (TRS) including H_2S. Municipal waste combustors are also regulated for the following pollutants: organics (measured as total tetra- through octa-chlorinated dibenzo-p-dioxins and dibenzofurans), metals (measured as particulate matter), acid gases (measured as sulfur dioxide and hydrogen chloride). Municipal solid waste landfills are also regulated for non-methane organic compounds (NMOC).

Hazardous Air Pollutants: Emissions units emit one or more of HAP as defined in Rule 62-210.200, F.A.C.

Project Description

The applicant requests an air construction permit to authorize modifications to the No. 4 Combination Boiler (EU-016). This boiler is a spreader-stoker furnace originally manufactured by Babcock & Wilcox (B&W) and constructed in 1965. It has not been modified or reconstructed as defined in the New Source Performance Standards (NSPS) provisions. The permitted capacity is 512.7 million British thermal units (MMBtu) per hour. Currently, the No. 4 Combination Boiler fires bark and wood waste as the primary fuel and residual oil as a startup and supplemental fuel. Particulate matter emissions are currently controlled with a multiple cyclone (multiclone) pre-cleaner followed in series by an electrostatic precipitator (ESP).

The maximum heat input rate for the existing oil burners is 418.6 MMBtu per hour, which is the physical capacity of the installed burners. The current permit imposes a federally enforceable cap of 5.1 million gallons of residual fuel oil fired during any consecutive 12-months. The maximum sulfur content of the residual oil is 2.35% by weight, which makes the No. 4 Combination Boiler one of the larger sources of potential SO_2 emissions (~ 983 tons/year).

The applicant proposes to implement the project in two phases. The initial phase is scheduled for an outage in May/June of 2008 and will include:

- Upgrades to the bark/wood delivery system with new air swept bark conveyors and feed bin to increase bark/wood firing rate;
- Increasing the maximum hourly heat input rate from 512.7 to 564 MMBtu per hour of bark/wood burning and restrict the annual bark/wood burning to 4,042,127 MMBtu;
- Installation of a new overfire air (OFA) system;
- Installation of a new mechanical collector to replace the existing multiclone pre-cleaner;
- Installation of a bottom ash handling system;
- Modification of ductwork to use the existing multiclone/ESP/stack from the No. 5 Power Boiler (which has been converted to natural gas) to serve the No. 4 Combination Boiler in parallel with the existing multiclone/ESP/stack; and
- Modification of ductwork to introduce the dilute non-condensible gases into the new OFA system.

The second phase is to convert the supplemental residual oil firing system for the No. 4 Combination Boiler to natural gas and permanently discontinue use of residual oil. This phase includes installation of a low-NO_X gas burner system with a capacity of 427 MMBtu per hour as well as additional pipeline capacity from the natural gas vendor, the Florida Gas Transmission Company (FGTC). Although gas is currently provided to the plant, the facility recently converted the No. 5 Power Boiler to natural gas. The FGTC indicates that additional lateral and metering equipment will be necessary to provide the additional capacity necessary for the No. 4 Combination Boiler. The FGTC estimates the availability of natural gas for this project in approximately 2 to 3 years depending on the siting process for new pipelines as well as construction. The mill is committed to completing conversion of the No. 4 Combination Boiler to natural gas within 180 days of completion of the necessary pipeline modifications by FGTC.

Reviewing and Processing Schedule

08/18/06: Request for additional information (project No. 1070005-038-AC) that pertained to the No. 4 Combination Boiler;

06/01/07: Receipt of additional information;

06/29/07: Request for additional information;

11/13/07: Receipt of additional information;

11/14/07: Filing of an Electronic Permit Submittal and Processing (EPSAP);

11/29/07: Receipt of additional information;

12/13/07: Request for additional information (e-mail);

12/24/07: Receipt of the PE Seal page associated with the EPSAP filed on November 14, 2007;

01/11/08: Receipt of additional information;

01/22/08: Receipt of additional information; and, deemed complete.

2. RULE APPLICABILITY

State Regulations

This project is subject to the applicable rules and regulations defined in the following generally applicable Chapters of the F.A.C.: 62-4 (Permits); 62-204 (Air Pollution Control – General Provisions: Ambient Air Quality Requirements, PSD Increments, and Federal Regulations Adopted by Reference); 62-210 (Stationary Sources – General Requirements: Permits Required, Public Notice, Reports, Stack Height Policy, Circumvention, Excess Emissions, and Forms); 62-212 (Stationary Sources - Preconstruction Review: PSD Review and BACT); 62-213 (Operation Permits for Major Sources of Air Pollution: Title V Air Operation Permits); 62-296 (Stationary Sources - Emission Standards); and 62-297 (Stationary Sources – Emissions Monitoring: Test Methods and Procedures, Continuous Monitoring Specifications, and Alternate Sampling Procedures). The No. 4 Combination Boiler is currently subject to the following industry-specific and PSD preconstruction review regulations:

- Rule 62-296.404, F.A.C. (Kraft Pulp Mills) regulates the No. 4 Combination Boiler for TRS emissions.
- Rule 62-296.410, F.A.C. (Carbonaceous Fuel Burning Equipment) regulates the No. 4 Combination Boiler for PM emissions.
- Rule 62-212.400, F.A.C. PSD preconstruction review regulations.

This project does not impose any newly applicable requirements pursuant to Rules 62-296.404 and 62-296.410, F.A.C.

Federal Regulations

The U. S. Environmental Protection Agency establishes air quality regulations in Title 40 of the Code of Federal Regulations. Part 60 identifies NSPS for a variety of industrial activities. Part 61 specifies the 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 given source categories. The Department adopts these federal regulations in Rule 62-204.800, F.A.C.

<u>NSPS Applicability</u>

The proposed modifications to the No. 4 Combination Boiler provide for a capacity increase (512.7 to 564 MMBtu per hour) by increasing the firing rate of the primary fuel of bark/wood. The firing of residual fuel oil will not change as a result of this project. Natural gas will be added as a new fuel. The applicant estimates the proposed project will cost $5.5 million, which is approximately 18% of the estimated cost of a new boiler of similar size ($30 million). Therefore, the project is not considered "reconstruction" as defined by the NSPS provisions.

The capacity increase could have the potential to increase the maximum hourly emissions rates, which would subject the boiler to the NSPS provisions of Subpart Db of 40 CFR 60 for Industrial-Commercial-Institutional Steam Generating Units. For units fired with wood or oil, Subpart Db regulates PM emissions, but the applicant maintains that PM emissions will decrease as a result of the project because of the control equipment modifications. For units fired with oil, Subpart Db also regulates NO_X and SO_2 emissions, but the maximum oil firing rate will not increase. For units fired with natural gas, Subpart Db regulates NO_X emissions. The applicant is unsure if the maximum hourly NO_X emissions rate will increase after the installation of the gas-fired low-NO_X burners and a new OFA system. There is very limited NO_X emissions data because NO_X emissions have not been previously regulated. Pursuant to 40 CFR 60.14(b)(2), the applicant requests that the Department postpone the NSPS applicability determination until performance tests have been conducted in accordance with Appendix C in 40 CFR 60 (Determination of Emissions Rate Change), which may include the installation and use of a certified

NO_X continuous emissions monitoring system (CEMS).

NESHAP Applicability

The No. 4 Combination Boiler was subject to the NESHAP provisions for existing units in Subpart DDDDD of 40 CFR 63 for Industrial, Commercial and Institutional Boilers and Process Heaters. This final regulation had a compliance date of September 13, 2007; however, the regulation was recently vacated by EPA and is no longer applicable.

PSD Applicability

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

New projects at existing PSD-major stationary sources are reviewed for PSD applicability based on net emissions increases from the project. Each PSD pollutant is evaluated for applicability based on emissions thresholds known as the Significant Emission Rates as defined in Rule 62-210.200, F.A.C. Pollutant emissions from the project exceeding these rates are considered "significant increases". In addition, a project may include a PSD netting analysis that considers all emissions increases as well as all emissions decreases for a 5-year period contemporaneous with the project to determine whether or not a PSD significant emissions increase will occur. Although a facility may be "major" based on just one PSD pollutant, the project may have a significant increase in several PSD pollutants. For each significant PSD pollutant increase, the applicant must employ the Best Available Control Technology (BACT) to minimize emissions and conduct an air quality analysis that demonstrates emissions from the project will not cause or contribute to adverse ambient impacts.

PSD Applicability for the Project

The project is located in Putnam County, which is in an area that is currently in attainment with the state and federal AAQS or otherwise designated as unclassifiable. The existing facility belongs to one of the 28 PSD Major Facility Categories (Kraft Pulp Mills) as defined for major stationary sources in Rule 62-210.200, F.A.C. Potential emissions of at least one pollutant from the existing plant are greater than 100 tons per year, which makes the facility a PSD-major stationary source of air pollution. Therefore, the project must be reviewed for PSD applicability.

The applicant conducted a netting analysis to determine PSD applicability for the affected unit considering all emissions increases as well as all emissions decreases for a 5-year period contemporaneous with the project. The following table summarizes the applicant's PSD netting analysis for this project. Baseline represents a 2-year period in last 10 years; Future Potential is maximum expected post-project; Contemporaneous Emission Changes represent difference between baseline and emissions increases or decreases from other projects within 5 years; and Net Emission Changes = Contemporaneous Emission Changes + [Future Potential – Baseline].

Pollutant	Emissions in Tons per Year [2]					Subject to PSD?
	Baseline	Future Potential	Contemporaneous Emission Changes	Net Emissions Change	PSD Significant Emission Rates	
CO	2094.7	4024.7	19.6	1949.5	100	Yes
NO_X	1504.5	2009.4	- 3.4	501.5	40	Yes
PM	530.0	659.7	- 6.7	122.9	25	Yes

Pollutant	Emissions in Tons per Year [2]					Subject to PSD?
	Baseline	Future Potential	Contemporaneous Emission Changes	Net Emissions Change	PSD Significant Emission Rates	
PM_{10}	433.5	534.6	- 4.3	96.8	15	Yes
SAM	183.5	20.4	0.3	- 162.8	7	No
SO_2	4179.2	290.9	- 362.0	- 4250.3	40	No
TRS	26.0	83.7	- 53.5	4.2	10	No
VOC	329.2	812.8	- 58.10	425.5	40	Yes
Pb	0.260	0.40	- 0.005	0.135	0.6	No
Hg	0.0059	0.0095	-0.000081	0.0034	0.1	No
Fl	0.449	0.000	- 0.027	- 0.475	3	No

This analysis includes the following contemporaneous projects: Project No. 1070005-007-AC for MACT I compliance; Project No. 1070005-017-AC also for MACT I compliance; Project No. 1070005-018-AC for the new package boiler; Project No. 1070005-024-AC for the brown stock washer and oxygen delignification system; Project No. 1070005-028-AC (PSD-FL-341) for the bark hog project; Project No. 1070005-038-AC (PSD-FL-380) for the No. 4 Recovery Boiler, No. 4 Multiple Effect Evaporator set, No. 4 Power Boiler, No. 5 Power Boiler and No. 4 Lime Kiln; and Project No. 1070005-050-AC for the No. 4 Recovery Boiler related to SO_2 emissions on oil.

Based on the applicant's netting analysis, the project is subject to PSD preconstruction review for CO, NO_X, PM/PM_{10} and VOC emissions. For each of these pollutants that will increase from the No. 4 Combination Boiler, the applicant is required to propose BACT controls and conduct a supporting air quality analysis to determine ambient impacts.

General Requirements for BACT Reviews

Pursuant to Rule 62-210.200, F.A.C., the "Best Available Control Technology" or "BACT" is defined as:

(a) *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.*

(b) *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.*

(c) *Each BACT determination shall include applicable test methods or shall provide for determining compliance with the standard(s) by means which achieve equivalent results.*

(d) *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.*

The Department conducts case-by-case BACT determinations in accordance with the requirements given above. In general, the Department conducts such reviews consistent with the "top-down methodology" described by EPA.

General Requirements for the PSD Air Quality Analysis

In addition to the required BACT determinations, a PSD preconstruction review also requires an air quality analysis for each significant PSD pollutant. The air quality analysis consists of: an air dispersion modeling analysis to estimate the resulting ambient air pollutant concentrations; a comparison of predicted project concentrations with the National AAQS (NAAQS) and PSD increments; an analysis of the air quality impacts from the proposed project upon soils, vegetation, wildlife, and visibility; and an evaluation of the air quality impacts resulting from associated commercial, residential, and industrial growth related to the proposed project. The proposed project requires the following air quality analyses: a significant impact analysis for CO, nitrogen dioxide (NO_2) and PM_{10}; a PSD increment analysis for NO_2; an AAQS analysis for NO_2; and, an analysis of impacts on soils, vegetation, and visibility and of growth-related air quality modeling impacts.

3. BACT REVIEW FOR THE NO. 4 COMBINATION BOILER

Discussion of Emission Changes

Currently, the No. 4 Combination Boiler fires bark/wood waste as the primary fuel and residual fuel oil as a startup and supplemental fuel. The conversion of the No. 5 Power Boiler to natural gas as the sole fuel and the eventual conversion of the No. 4 Combination Boiler from supplemental fuel oil to natural gas allow this project to avoid PSD preconstruction for SO_2 and SAM emissions. Based on the contemporaneous PSD netting analysis, the project is subject to PSD preconstruction review for CO, NO_X, PM/PM_{10} and VOC emissions. For reference, the following table summarizes the applicant's estimate of potential emissions changes for these pollutants resulting from this project without accounting for other contemporaneous projects (as shown in prior table).

Pollutant	Emissions in Tons per Year		
	Baseline	Future Potential	Change
CO	780.3	1235.2	+ 454.9
NO_X	413.2	592.9	+ 179.7
PM	99.2	98.8	- 0.4
PM_{10}	71.9	73.1	+ 1.2
VOC	22.4	42.0	+ 19.6

When firing fuel oil, AP-42 Emission Factors estimates that the PM_{10} portion is 63% of the PM emissions (Table 1.3-4). When firing wood residue, AP-42 Emission Factors estimates that the PM_{10} portion is 74% of the PM emissions (Table 1.6-1).

BACT Review for PM/PM_{10}/$PM_{2.5}$ Emissions

Throughout this evaluation, particulate matter emissions are referred to as PM emissions, which serve as a surrogate for regulating PM_{10} and $PM_{2.5}$ emissions.

<u>Discussion of PM Emissions</u>

The No. 4 Combination Boiler is a spreader-stoker furnace. Bark/wood enters the top of the furnace through a fuel chute and is spread in a thin, even bed on a traveling grate. Smaller wood/bark particles burn in suspension, but the bulk of the fuel burns on the grate. Combustion occurs in three stages in the single furnace chamber: the evaporation of moisture in the fuel, the distillation and burning of volatile matter, and the burning of fixed carbon. As-fired wood has relatively high moisture content (~ 50%) and may include sand and other non-combustibles, which adversely affects combustion. Based on AP-42 Table 1.6-1, the uncontrolled PM emissions factor for firing wet wood and bark is 0.56 lb/MMBtu.

Residual fuel oil may be fired from wall-mounted fuel oil guns for startup and as a supplemental fuel to maintain constant steam production. Based on AP-42 Table 1.3-1, residual oil with a sulfur content of 2.35% would result in an uncontrolled PM emissions factor of 0.165 lb/MMBtu. Natural gas contains negligible amounts of ash or moisture and is nearly completely combusted. Based on AP-42 Table 1.4-2, the uncontrolled filterable PM emissions factor for natural gas is 0.002 lb/MMBtu.

Available Technologies for Controlling PM Emissions

The main abatement options for controlling PM emissions include:

- Fabric filters (99.9% control);
- Electrostatic precipitators (99.9% control);
- Wet scrubbers (70% to 99% control for wet venturi scrubbers);
- Cyclones and mechanical collectors (70% to 90%);
- Fuel switching (variable); and
- Combustion improvements (variable).

With achievable control efficiencies of 99.9%, the top control options are either a fabric filter or an ESP. Although fabric filters are technically feasible and in use in certain wood-fired applications, there are concerns regarding fire danger because of collecting fine, combustible carbonaceous fly ash on the filter bags. In addition, the high moisture content of the flue gas exhaust may cause blinding and premature plugging. Approximately 60% of the PM BACT determinations for biomass-fired industrial boilers in EPA's RACT/BACT/LAER Clearinghouse (RBLC) are based on the use of an ESP or a multiclone-ESP combination. Currently, the No. 4 Combination Boiler controls PM emissions with a multiclone-ESP combination. The current PM emissions standards are 0.3 lb/MMBtu when firing carbonaceous fuel and 0.1 lb/MMBtu when firing fuel oil.

Applicant's PM BACT Proposal

Between 2001 and 2007, the applicant conducted seven PM tests using EPA Method 5 while burning both residual fuel oil and bark/wood. The average of these tests is 0.054 lb/MMBtu. The tests indicate the effectiveness of the existing multiclone-ESP combination. For the project, the applicant proposes the following improvements:

Test Date	lb PM/MMBtu
09/25/07	0.06
04/24/06	0.04
08/18/05	0.04
01/08/04	0.09
01/08/03	0.06
06/19/02	0.047
07/18/01	0.04

- Natural gas will eventually replace supplemental residual oil, which will reduce overall PM emissions;
- Upgrades to the bark/wood delivery system will improve combustion;
- Installation of a new OFA system will reduce incomplete combustion of the bark/wood;
- Installation of a bottom ash handling system will help prevent re-entrainment of captured fly ash into the exhaust;
- Replacement of the existing multiclone with new efficient mechanical collectors will remove additional PM emissions and avoid overloading the ESP; and

- The existing system will be greatly enhanced by splitting the flue gas exhaust and controlling half with new mechanical collectors/existing No. 4 Combination Boiler ESP and the other half with the existing mechanical collectors/No. 5 Power Boiler ESP.

Although the proposed system should result in substantial improvements, the applicant is concerned with the increased bark/wood firing rate. Based on the current system and proposed modifications, the applicant proposes a PM BACT standard of 0.040 lb/MMBtu. The EPA RBLC identifies PM BACT limits for similar boilers and control systems ranging from 0.02 to 0.10 lb/MMBtu with the majority in the range of 0.02 to 0.03 lb/MMBtu. The proposed PM BACT is within the range of previous BACT determinations and more stringent than the PM standard of 0.07 lb/MMBtu specified for existing units in the vacated NESHAP Subpart DDDDD of 40 CFR 63.

Also, the applicant requested to retain the current visible emissions standards in Rule 62-296.410(1)(b), F.A.C.:

- ≤ 30% opacity except for 40% opacity for no more than 2 minutes in any one hour, when burning bark and wood waste and residual fuel oil, and
- ≤ 20% opacity except for 40% opacity for no more than 2 minutes in any one hour, when burning only residual fuel oil.

The proposed method of compliance is conducting tests in accordance with EPA Method 9.

Department's PM BACT Review

The Department accepts that the multiclone-ESP combination is capable of achieving the top control. This is supported by information in the EPA RBLC that 22 of 34 recent PM BACT determinations identify an ESP or a multiclone-ESP combination as the control equipment basis. However, the proposed standard of 0.040 lb/MMBtu does not appear to reflect the full capability of the modified system considering the improvements. Assuming an uncontrolled PM emissions factor (AP-42) for firing wet wood and bark of 0.56 lb/MMBtu, the average control efficiency to achieve the proposed standard would be only 92.9%. The following two cases for sister Georgia-Pacific facilities support a lower PM BACT standard.

- At the Monticello mill in Mississippi, the existing combination boiler rated at 917 MMBtu/hour was manufactured by Babcock & Wilcox and constructed in 1967. An ESP is used to control PM emissions from the existing unit. Three prior performance tests yielded the following emissions rates: 0.014 lb/MMBtu, 0.0068 lb/MMBtu and 0.0051 lb/MMBtu (average of 0.0086 lb/MMBtu). The boiler has a PM BACT limit of 0.1 lb/MMBtu for all fuels.
- At the Camas mill in Washington, the existing combination boiler rated at 400 MMBtu/hour was manufactured by Foster Wheeler and constructed in 1991. An ESP is used to control PM emissions from the existing unit. Five prior performance tests yielded the following emissions rates: 0.0039 lb/MMBtu, 0.0018 lb/MMBtu, 0.0016 lb/MMBtu, 0.0019 lb/MMBtu and 0.0025 lb/MMBtu (average of 0.0023 lb/MMBtu). The boiler has a PM BACT limit of 0.02 lb/MMBtu for all fuels.

Assuming an uncontrolled PM emissions factor (AP-42) for firing wet wood and bark of 0.56 lb/MMBtu, the average control efficiency for the Monticello boiler would be 98.5% and for the Camas boiler would be 99.6%. These control efficiencies more reasonably reflect the control levels achievable for a modified older unit and a newer unit. Modifications to the existing No. 4 Combination Boiler at the Palatka mill should be able to achieve similar results. As previously mentioned, the EPA RBLC identifies that the majority of PM BACT limits for similar boilers and control systems range from 0.02 to 0.03 lb/MMBtu.

For purposes of comparison, the NSPS Subpart Db standard for PM emissions is 0.030 lb/MMBtu heat input for boilers constructed, reconstructed or modified after February 28, 2005, that combust coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels [60.43b(h)(1)]. Assuming an uncontrolled PM emissions factor (AP-42) for firing wet wood and bark of 0.56 lb/MMBtu, this standard represents a control efficiency of only 94.6%. Assuming an uncontrolled PM emissions factor (AP-42) for firing 2.35% sulfur fuel oil of 0.165 lb/MMBtu, this standard represents a control efficiency of only 81.8%. Assuming an uncontrolled filterable PM emissions factor (AP-42) for firing natural gas of 0.002 lb/MMBtu, no additional control would be needed to meet a standard of 0.03 lb/MMBtu.

The following general equation represents an approximation of the control efficiency for an ESP:

$\eta = 1 - e^{-w(A/Q)}$, where:

η is the control efficiency

e is the logarithm base function and equal to ~2.718

w is the migration velocity

A is the collection area of the ESP

Q is the volumetric flow rate

$e^{-w(A/Q)}$ is the exponential term representing the fraction of the material that passes the ESP

ESP A/Q	Collection Efficiency
1	90%
2	99%
3	99.9%
4	99.99%
5	99.99%

In general, the control efficiency is a strong function of the ratio of the ESP collection area to the volumetric flow rate. The table[1] shows how this ratio affects the control efficiency. For example, doubling the A/Q ratio improves the efficiency from 90% to 99%.

The proposal includes the use of mechanical dust collectors as precleaners to the ESP. This is common for wood-fired boilers to remove the larger ash particles. The application indicates that the mechanical dust collectors will have a removal efficiency of 80% to 90% and the ESP will have a removal efficiency of 99.5%. Based on filterable PM emissions factors from Table 1.6-1 in AP-42, the following table summarizes several scenarios for controlling PM emissions with a combination of mechanical dust collectors and an ESP.

Fuel	Uncontrolled PM Emissions Factor, lb/MMBtu	Mechanical Dust Collectors Control Efficiency	ESP Control Efficiency	Controlled PM Emissions lb/MMBtu
Bark/Wet Wood	0.56	40%	91%	0.030
		55%	95%	0.013
		80%	99.5%	0.001
Dry Wood	0.40	40%	91%	0.022
		55%	95%	0.009
		80%	99.5%	0.0004
Wet Wood	0.33	40%	91%	0.018
		55%	95%	0.007
		80%	99.5%	0.0003

As shown in the table, this combination of controls can achieve very low PM emissions rates.

When firing bark/wood/oil, the applicant requests an opacity standard of 30% or less, except for up to 40% opacity for no more than 2 minutes in any one hour. Based on ten opacity tests conducted from 1997 to 2007 using EPA Method 9, the average opacity is 5.1 %. Also for purposes of comparison, the NSPS Subpart Db standard is less than or equal to 20% opacity (6-minute average), except for one 6-minute period per hour of not more than 27%. With the proposed improvements, the modified boiler will readily meet a standard of 20%

[1] Table 3-2 in APTI Course SI:412B, Electrostatic Precipitator Plan Review, EPA 450/2-82-019, July 1983.

opacity.

Based on a review of the available information, the Department establishes the following draft PM BACT standards:

> As determined by EPA Method 5, PM emissions shall not exceed 0.030 lb/MMBtu and 16.9 lb/hour when firing any combination of authorized fuels.
>
> As determined by EPA Method 9, visible emissions shall not exceed 20% opacity (6-minute average), except for one 6-minute period per hour of not more than 27% opacity when firing any combination of authorized fuels.

Compliance shall be determined by conducting initial and annual tests. Each of the two stacks shall be tested simultaneously to demonstrate compliance with these standards. During initial compliance tests, the boiler shall operate at permitted capacity while firing only bark/wood.

BACT Review for CO and VOC Emissions

Discussion of CO and VOC Emissions

Combustion is a chemical process occurring from the rapid combination of oxygen (air) with combustible materials (fuel) that produces heat. Once the air and fuel are in contact, the following conditions are needed to complete combustion: temperature high enough to ignite fuel and air mixture; turbulent mixing of fuel and air; and sufficient residence time for the reaction to occur. In an ideal combustion process, the final products include carbon dioxide, water and energy in the form of heat. When conditions are less than ideal, combustion will be incomplete and will generate smoke, CO, PM and VOC emissions. For comparison purposes, the following table identifies the average CO and VOC emissions rates for combusting bark/wood, fuel oil and natural gas in an industrial boiler.

Fuel Type	CO Emissions		VOC Emissions	
	lb/MMBtu	Reference	lb/MMBtu	Reference
Bark/Wood	0.60	AP-42, Table 1.6-2, A Rating	0.038	AP-42, Table 1.6-3, D Rating
Residual Oil	0.033	AP-42, Table 1.3-1, A Rating	0.002	AP-42, Table 1.3-3, A Rating
Natural Gas	0.082	AP-42, Table 1.4-1, B Rating	0.005	AP-42, Table 1.4-2, C Rating

Available Technologies for Controlling CO and VOC Emissions

The main control abatement options for reducing CO and VOC emissions include the following.

Thermal Oxidizers: Thermal oxidizers provide increased temperatures, mixing and residence time to complete combustion. Depending on the CO and VOC concentrations, such units may require high fuel firing rates of natural gas to maintain adequate oxidizing temperatures (e.g., 1200° F for one second residence). In general, thermal oxidizers are used for gas streams with relatively high concentrations of VOC emissions (e.g., 1500 ppmv). Reductions of more than 98% are achievable depending on the specific pollutants, inlet concentrations and other factors. [EPA-452/F-03-022]

Oxidation Catalysts: These systems use specialized catalysts to complete oxidation at lower temperatures, typically at temperatures between 600° F and 800° F. If the inlet exhaust temperature is less than this range, additional fuel such as natural gas must be fired to maintain an effective destruction temperature. Catalytic oxidizers are suited best for systems with low exhaust flows, flue gas with little variation in the type and concentration of VOC, and in applications where catalyst poisons (e.g., chlorine, zinc, silicone, sulfur) or other fouling contaminants (e.g., heavy hydrocarbons, particulates) are not present. Reductions of more than 95% are achievable depending on the specific pollutants, inlet concentrations and other factors. [EPA-452/F-03-018]

Combustion Modifications: These techniques vary depending on the combustion source, but may include: new burners, grate modifications, fuel feed improvements, OFA, etc.

Applicant's CO and VOC BACT Proposal

A thermal oxidation system is a technically feasible add-on control option. Since the exhaust temperature leaving the ESP is low (~ 340° F), the flue gas must be heated to an effective operating temperature range by firing additional natural gas with a direct flame burner. Although CO emissions are expected to be in the range of 400 to 800 ppmv, VOC emissions are expected to be only 3 to 10 ppmv. The applicant estimates natural gas usage for a thermal oxidation system to cost approximately $840,000 per year. Therefore, thermal oxidizers are not considered for the control of boiler exhausts because of the large additional fuel requirements and high costs necessary to maintain the effective oxidizing temperature.

A catalytic oxidation system is a technically feasible add-on control option. Since the exhaust temperature leaving the ESP is low (~ 340° F), the flue gas must be heated to an effective operating temperature range by firing additional natural gas with a duct burner. The applicant estimates the annual operating costs for a duct burner system at $2.4 million dollars. Besides these high operating costs, there is considerable uncertainty related to poisoning and fouling of the catalyst from firing bark/wood. The flue gas may contain significant amounts of chlorine, zinc, silicone and metals, which can poison and prematurely deactivate the catalyst. There will also be residual PM emissions remaining in the flue gas after the ESP that can blind the catalyst and reduce the effectiveness. Gradually, PM emissions may plug the catalyst and force early repair or replacement. The applicant concludes that catalytic oxidation is impractical and cost prohibitive. The additional costs would negate a significant portion of the cost savings that could be realized by firing less fuel oil and more bark/wood, which is a primary objective and would substantially challenge the viability of the proposed project.

The applicant proposes to install a new OFA system in the upper part of the No. 4 Combination Boiler to enhance complete combustion of all fuels and reduce CO and VOC emissions. Staged combustion with OFA promotes uniform mixing and complete combustion of the fuel. The applicant predicts a 25% reduction in CO emissions will be achievable with the new OFA system.

Previous BACT determinations for biomass-fired industrial boilers indicate that CO and VOC control is generally based on efficient boiler design and good combustion practices, with several including the use of an OFA system. The EPA RBLC indicates CO BACT determinations ranging from 0.03 to 2.25 lb/MMBtu for biomass-fired industrial boilers. The EPA RBLC indicates VOC BACT determinations ranging from 0.007 to 0.05 lb/MMBtu for biomass-fired industrial boilers. The large range is attributed to differences in boiler designs, fuels and operation.

Based on a guarantee for the natural gas burners, maximum CO emissions will be 0.10 lb/MMBtu when firing only natural gas with a heating value of 1000 Btu per ft^3. The guarantee is from the Todd Combustion Group, a fluid dynamics combustion consulting company associated with the John Zink Company, which is a burner manufacturer. Based on AP-42 for firing natural gas in an industrial boiler, VOC emissions are expected to be 0.005 lb/MMBtu. Based on AP-42 for firing residual oil in an industrial boiler, CO and VOC emissions are expected to be 0.033 and 0.002 lb/MMBtu, respectively.

For any combination of fuels, the applicant proposes a CO standard of 0.50 lb/MMBtu and 282.0 lb/hour and a VOC standard of 0.017 lb/MMBtu and 9.6 lb/hour. The maximum predicted CO impacts for the proposed project are less than the EPA Class I and II significant impact levels. Additional CO controls would result in an insignificant reduction of ambient impacts that are already less than the EPA significance levels for both Class I and II areas.

Department's BACT Review

The following table summarizes cost information developed from project data and two EPA fact sheets related to thermal and catalytic control options.

Oxidizer	Capital Cost		Annualized Cost		CO and VOC Reductions [b]	Cost Effectiveness
	Factor	Cost [a]	Factor	Cost [a]		
Thermal [c]	$25-$90/scfm	$4.3-$15.6 million	$8-$98/scfm	$1.4-$17 million	1251	$1119-$13,589/ton
Catalytic [d]	$22-$90/scfm	$3.8-$15.6 million	$8-$50/scfm	$1.4-$8.7 million	1213	$1154-$7172/ton

a. The volumetric flow rate at permitted capacity is 135,400 dscfm, which is 173,590 scfm @ 22% water vapor.

b. This assumes uncontrolled CO + VOC emissions of 1277 tons/year and a control efficiency of 98% for thermal oxidation and 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 bark/wood-fired boiler, the costs would be near the higher end of the range because of the relatively low uncontrolled CO and VOC levels as well as the low flue gas temperatures leaving the ESP, which result in high natural gas 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 agrees that thermal and catalytic oxidation systems are not appropriate and are cost prohibitive for controlling CO and VOC emissions from the bark/wood-fired boiler. The Department accepts the applicant's proposal to install a new OFA system in the upper part of the No. 4 Combination Boiler to enhance complete combustion of all fuels and reduce CO and VOC emissions.

Draft CO BACT Determination

The following information was also considered in determining the draft CO BACT standard.

- There are no existing CO emissions data for the existing boiler.
- The low-NO_X burner system for firing natural gas will be selected based on a design CO specification of 0.10 lb/MMBtu.
- The existing residual fuel oil system will generate CO emissions rates averaging 0.033 lb/MMBtu based on the corresponding AP-42 emission factor.
- For biomass-fired industrial boilers, the EPA RBLC identifies CO BACT standards in the range from 0.03 to 2.25 lb/MMBtu. For comparison, the biomass-fired industrial boilers at the Georgia-Pacific sister mills in Monticello (modified 1967 boiler) and Camas (1991 boiler) show an average CO emissions rate of 0.46 and 0.13 lb/MMBtu, respectively. The CO emission standard for the Monticello boiler is 1.36 lb/MMBtu and for the Camas boiler is 0.60 lb/MMBtu.
- The primary fuel for the No. 4 Combination Boiler is bark/wood with residual oil and natural gas fired as supplemental fuels. Residual oil firing is limited to a capacity factor of approximately 21% of the maximum annual oil firing capacity. Natural gas firing is not synthetically limited.
- According to the recently vacated NESHAP Subpart DDDDD provisions, complete combustion in a solid fuel-fired boiler results in CO levels of approximately 400 ppmvd @ 7% oxygen or less as determined by CEMS. This is approximately equivalent to 0.41 lb/MMBtu. However, the vacated standard allowed the exclusion of emissions data collected during periods of startup, shutdown, malfunction and operation below 50% of the rated capacity.

Based on a review of the available information, the Department establishes the following draft CO BACT standards:

As determined by CEMS data, CO emissions shall not exceed 0.50 lb/MMBtu and 282.0 lb/hour when firing any combination of authorized fuels based on a 30-day rolling average. Emissions data collected during startup, shutdown and malfunction may be excluded from the compliance demonstration.

Although the draft standard is slightly higher than the vacated NESHAP Subpart DDDDD provisions, it does not allow the exclusion of CEMS data collected during periods of operation below 50% of rated capacity. This is to discourage operation at these levels where combustion may not be complete. It also considers the applicant's design expectations for the modified existing boiler.

Draft VOC BACT Determination

The following information was considered in determining the draft VOC BACT standard.

- There are no existing VOC emissions data for the existing boiler.
- The low-NO_X burner system for firing natural gas will generate VOC emissions rates averaging 0.005 lb/MMBtu based on the corresponding AP-42 emission factor.
- The existing residual fuel oil system will generate VOC emissions rates averaging 0.002 lb/MMBtu based on the corresponding AP-42 emission factor.
- The existing spreader stoker boiler firing bark/wood will generate VOC emissions rates averaging 0.028 lb/MMBtu based on the corresponding AP-42 emission factor.
- Addition of the OFA system and improvements to the bark/wood feeders will improve overall combustion and reduce VOC emissions from current levels.
- The Okeelanta Cogeneration Plant operates three boilers constructed in 1997 that fire wood and bagasse. The VOC limit is 0.05 lb/MMBtu with 24 stack tests demonstrating compliance. Of these tests, 22 tests show VOC emissions rates below 0.022 lb/MMBtu.
- A test conducted for the No. 3 Bark Boiler at the Smurfit-Stone Container Panama City Mill shows actual emissions of 0.01 lb/MMBtu.

Based on a review of the available information, the Department establishes the following draft VOC BACT standards:

> As determined by EPA Method 25A, VOC emissions shall not exceed 0.02 lb/MMBtu and 11.3 lb/hour when firing any combination of authorized fuels.

Initial compliance shall be demonstrated by stack testing conducted while firing bark/wood at permitted capacity. Thereafter, compliance shall be assumed if the unit remains in compliance with the CO standards demonstrated by CEMS. Pursuant to Rule 62-297.310(7)(b), F.A.C., "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."

BACT Review for NO_X Emissions

<u>Discussion of NOx Emissions</u>

In general, NO_X emissions are generated by the following three mechanisms.

- Thermal NO_X occurs in the high-temperature zone near the burner itself. The formation of thermal NO_X is affected by oxygen concentrations, peak flame temperatures and the time of exposure to peak temperatures. As these three components increase, thermal NO_X emissions will increase.

- Fuel NO_X is generated from nitrogen available in the fuel that is oxidized to NO_X.
- Prompt NO_X occurs in the flame itself and results from the early reactions of nitrogen molecules in the combustion air and hydrocarbon radicals in the fuel.

For wood-fired boilers, excess air is provided to ensure adequate oxygen for the combustion process, which results in moderately high oxygen levels (~ 7% oxygen). Operators attempt to maintain high furnace temperatures to combust all of the fuel. Wood-fired boilers are also designed with moderate furnace residence times to ensure complete combustion. These factors lead to the generation of significant amounts of thermal NO_X emissions. Fuel NO_X emissions can be significant for bark/wood, but much less for residual oil and nearly negligible for natural gas. For combustion in conventional boilers and furnaces, prompt NO_X is generally insignificant when compared to the amounts of thermal and fuel NO_X emissions. Based on information in AP-42, average NO_X emissions from wood-fired, oil-fired, and natural gas-fired boilers are shown in the following table.

Fuel Type	NO_X Emissions	
	lb/MMBtu	Reference
Bark/Wood, > 20% moisture	0.22	AP-42, Table 1.6-2, A Rating
Bark/Wood, < 20% moisture	0.49	AP-42, Table 1.6-2, A Rating
Residual Oil	0.31	AP-42, Table 1.3-1, A Rating
Natural Gas	0.14	AP-42, Table 1.4-1, A Rating

Available Technologies for the Control of NOx Emissions

The following technologies are available for controlling NO_X emissions from industrial 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%.

Fuel Staging of Combustion: Combustion may be staged by dividing fuel into two streams instead of air. The first stream feeds primary combustion that operates in a reducing fuel-to-air ratio. The second stream is injected downstream of primary combustion, causing the net fuel-to-air ratio to be slightly oxidizing. Excess fuel in the primary combustion zone dilutes heat to reduce temperature. The second stream oxidizes the fuel while reducing the NO_X to N_2 and water vapor. Reductions in NO_X emissions vary from 35% to 50% depending on the project. Such systems have been successful on utility boilers with conventional fuels such as fuel oil and natural gas.

Natural Gas Reburn: Reburn uses a set of natural gas burners installed above the primary combustion zone. Natural gas is injected to form a fuel-rich, oxygen-deficient combustion zone above the main firing zone. Emissions of NO_X generated in the main firing zone travel upward into the reburn zone and are converted to N_2. The technology requires no catalyst, chemical reagents, or changes to any existing burners. Typical reburn systems also incorporate redesign of the combustion air system along with a water-cooled, pinhole grate to provide reduced excess air. For utility boilers, NO_X has been reduced by 35% 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%.

Low Excess Air (LEA): Excess combustion air has been correlated to the amount of thermal NO_X generated. Limiting the net excess air can reduce the thermal NO_X produced. Potential reductions in NO_X emissions vary up to 35% for certain applications.

Steam Injection: The injection of steam causes the stoichiometry of the mixture to be changed and reduces heat energy generated by combustion. These actions cause lower combustion temperatures, which in turn reduce the amount of thermal NO_X formed. Depending on the applications, potential reductions in NO_X emissions vary from 35% 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 NOx BACT Proposal</u>

The purpose of the project is to upgrade the No. 4 Combination Boiler to fire more bark/wood more efficiently and eventually replace the residual oil firing system with natural gas. Some of the upgrades may improve combustion and increase furnace temperatures, which tend to reduce CO, PM and VOC emissions. However, such changes may increase thermal NO_X emissions. The applicant intends to improve combustion and boiler efficiency without any substantial increases in NO_X emissions.

Based on the available NO_X control options, the applicant reviewed the following add-on control technologies: Fuel Tech Hybrid SNCR/SCR system; Fuel Tech SNCR system; Ecotube system (with and without SNCR); and a FGR system.

The baseline emissions used for the NO_X cost effectiveness analysis is 0.24 lb/MMBtu for bark/wood firing and 0.31 lb/MMBtu for residual fuel oil firing. The bark/wood factor is based on limited stack test data for the No. 4 Combination Boiler. The factor for firing residual fuel oil firing is based on AP-42 Table 1.3-1. These values reflect the best estimates of current NO_X emission levels from the existing No. 4 Combination Boiler. An annual capacity factor of 80% was used since the boiler has been historically operated at this level. The applicant does not predict that the annual capacity factor for the boiler will increase. Also, the destruction of stripper off gases in the boiler was not considered in the analysis since the boiler is only used as a backup control device for the thermal oxidizer.

Review of Fuel Tech Hybrid SNCR/SCR System: The total installed capital cost is estimated to be $8,100,000. The catalyst is projected to have a 3-year operational life. The total annual operating cost is estimated to be

\$1,800,000. Based on the NO_X reduction potentials of the control system of 65% for bark/wood and 40% for fuel oil, the cost effectiveness is \$6,457 per ton NO_X removed. This cost effectiveness is considered to be higher than the cost effectiveness that has been determined to be economically infeasible for existing industrial boilers in Florida. Also, there is significant uncertainty regarding the actual cost of the system, the performance of the system (i.e., catalyst life, maintenance, etc.) and the actual NO_X reduction that will be achieved, due to the lack of operating experience on industrial biomass-fired boilers. Therefore, the hybrid SNCR/SCR is rejected based on high costs.

Review of Fuel Tech SNCR System: The total installed capital cost is estimated to be \$3,400,000. The total annual operating cost is estimated to be \$717,500. Based on a potential NO_X reduction of 30% overall, the cost effectiveness is \$5,419 per ton NO_X removed. This cost effectiveness is considered to be higher than the cost effectiveness that has been determined to be economically infeasible for existing industrial boilers in Florida. Therefore, the applicant rejects this option based on high costs.

Review of Ecotube SNCR System: This system includes an OFA system with a retractable air injection lance. The lance is positioned above the grate to provide high-pressure air for thorough mixing and improved combustion. The tube can be retracted as needed for maintenance or adjustment. Urea can be injected into the tube for additional NO_X control. The total installed capital cost is estimated to be \$5,000,000 for the urea-based injection system. The total annual operating cost is estimated to be \$1,287,000. Based on the NO_X reduction potentials of 60% for bark/wood firing and 40% for fuel oil firing, the cost effectiveness is \$4,800 per ton of NO_X removed. This cost effectiveness is considered to be higher than the cost effectiveness that has been determined to be economically infeasible for existing industrial boilers in Florida. Therefore, the applicant rejects this option based on high costs.

Review of Ecotube System: Without the addition of urea injection, the total installed capital cost is estimated to be \$4,000,000 for the air injection lance system. The total annual operating cost is estimated to be \$860,000. Based on a potential NO_X reduction of 20% overall, the cost effectiveness is \$9,752 per ton NO_X removed. This cost effectiveness is considered to be higher than the cost effectiveness that has been determined to be economically infeasible for existing industrial boilers in Florida. Therefore, the applicant rejects this option based on high costs.

Review of FGR System: The total installed capital cost is estimated to be \$2,100,000. The total annual operating cost is estimated to be \$347,000. Based on a NO_X reduction potential of 15%, the cost effectiveness is \$5,374 per ton NO_X removed. This cost effectiveness is considered to be higher than the cost effectiveness that has been determined to be economically infeasible for existing industrial boilers in Florida. Therefore, the applicant rejects this option based on high costs. (The applicant notes a concern for potential increases in CO emissions caused by operating a FGR system in combination with an OFA system, which is planned in this boiler modification project. Although technically feasible as a single reduction strategy, the FGR system in combination with the proposed OFA system may not meet the mill's goal of reducing CO emissions as well as NO_X.)

Other Considerations

A study performed by NCASI in August of 2003 (Special Report No. 03-03), reports that the EPA suggests the use of \$2,000 per ton of NO_X removed as the criteria to determine what is considered economically feasible. Based on the economic analysis performed for these add-on control technologies, all result in cost effectiveness estimates that are considerably higher than \$2,000 per ton of NO_X removed. As such, these options are considered cost prohibitive.

The applicant does not believe that SNCR or SCR technologies have been demonstrated in practice on an older, existing, 100% biomass-fired industrial boiler because of the variable exhaust temperatures associated with the process. The applicant notes serious concerns related to achieving the proper temperature window and residence time for reaction of the urea. In addition, ammonia slip and unreacted urea may impinge on boiler tubes and cause premature boiler tube failure and other effects on downstream equipment (e.g., air heater, superheater, etc.) and result in additional maintenance and repair costs. For SCR systems, the applicant has additional concerns related to catalyst fouling and plugging resulting in loss of effectiveness and early catalyst replacement. For the retrofit of a 1967 boiler, the SCR and SNCR systems cannot be optimally designed because of the existing boiler configuration, the limited residence time for urea to react and changing temperatures within the boiler. These technical uncertainties and the high costs render the technologies infeasible for this boiler.

As shown in Attachment C of the application (including impacts from the No. 4 Lime Kiln and No. 4 Recovery Boiler), the maximum predicted NO_2 impacts for the proposed project are less than the AAQS and EPA Class I and II PSD increments. Additional NO_X controls for the No. 4 Combination Boiler would result in an insignificant reduction of ambient impacts that are already only slightly above the EPA significance levels for both Class I and II areas.

Energy penalties occur with the hybrid SNCR/SCR system, the Ecotube system with urea injection, and with the SNCR only NO_X control systems. Additional energy, water, and ammonia are all required for these systems.

Applicant's NO_X BACT Proposal

Of the remaining NO_X control options, the applicant proposes to use the following combination for the No. 4 Combination Boiler: the use of low-nitrogen fuels (e.g., bark/wood and natural gas), low-NO_X burner system for firing natural gas, optimizing excess air for the stoker grate, and adding an improved OFA system. The estimated cost of the OFA system is $1.03 million. These upgrades will improve combustion of all fuels and reduce potential NO_X emissions.

From a review of the EPA RBLC for similar wood-fired industrial boilers, previous NO_X BACT determinations range from 0.14 to 0.40 lb/MMBtu based on SNCR, low-NO_X burner system, good combustion practices or no controls. The lowest NO_X standards were 0.14 lb/MMBtu for a new bagasse-fired boiler and 0.15 lb/MMBtu for new bagasse/wood-fired boilers. For oil-fired industrial boilers, previous NO_X BACT determinations range from 0.37 to 0.70 lb/MMBtu based on low-NO_X burner systems and good combustion practices. The applicant proposes the following NO_X BACT standards:

0.24 lb/MMBtu and 135.4 lb/hour when firing bark/wood alone or with other authorized fuels

0.27 lb/MMBtu and 113.0 lb/hour when firing only residual fuel oil

0.15 lb/MMBtu and 64.1 lb/hour when firing only natural gas

Department's NOx BACT Review

The table summarizes the results of NO_X stack tests conducted on the No. 4 Combination Boiler from October 25 through 27 in 2005. As shown, the NO_X emissions rates range 0.21 to 0.34 lb/MMBtu lb/hour with an average of 0.26 lb/MMBtu. With the improvements to the fuel feeders and addition of the OFA system, the applicant believes a NO_X emissions rate of 0.24 lb/MMBtu is achievable.

Test	Tested NO_X Emissions	
	lb/MMBtu	lb/hr
1	0.24	93.5
2	0.21	95.5
3	0.24	103.5
4	0.27	81.3
5	0.21	92.0
6	0.26	103.2
7	0.28	104.4
8	0.34	101.0
9	0.32	114.6

The cost estimates provided by the applicant appear to be on the high end. This is likely because of the relatively low-to-moderate baseline NO_X emissions rate (0.22 to 0.31 lb/MMBtu) available for control and the retrofit of an older boiler, which results in low control efficiency estimates from the control equipment vendors. In a June 1st supplement to the application, the applicant provided additional cost information from Jacobs Engineering of Greenville, South Carolina. The engineering company indicates substantial additional costs related to the retrofit, which could drive the cost effectiveness for an SNCR system to approximately $7800/ton of NO_X removed. The Department considered the following with regard to the applicant's cost estimates.

- For the hybrid SNCR/SCR system, the applicant's total installed capital cost of $8.1 million. According to a report by the Northeast States for Coordinated Air Use Management[2], SCR costs can range up to $15,000/MMBtu to retrofit an industrial boiler. This would equate to approximately $8.5 million for the project, which is estimated as 40% of the capital equipment cost of a new boiler.
- For the SNCR systems, capital costs are more reasonable, but the estimated cost effectiveness remains high at approximately $5000/ton of NO_X removed because of low expected control efficiencies provided by the vendors.
- Although the Ecotube OFA and FGR systems are less capital intensive, the overall cost effectiveness of these systems appears to be more than $5000/ton of NO_X removed because of retrofit and control efficiency concerns.

As described under the PM BACT review section, Georgia-Pacific operates similar bark/wood-fired boilers (with supplemental natural gas) at the following two sister mills.

- At the Monticello mill in Mississippi, the existing combination boiler (917 MMBtu/hour) has a NO_X BACT limit of 0.31 lb/MMBtu. Actual tests results indicate emissions of 0.16 to 0.19 lb/MMBtu.
- At the Camas mill in Washington, the existing combination boiler (400 MMBtu/hour) has a NO_X BACT limit of 0.25 lb/MMBtu. Actual tests results indicate emissions of 0.14 to 0.17 lb/MMBtu.

Each of the boilers at the sister plants use low-NO_X burner systems, OFA systems and good combustion practices to minimize NO_X emissions.

The Department notes that application of SNCR has proven cost effective and been successful for several cases in Florida including several Wheelabrator plants, the Okeelanta cogeneration plant and a new bagasse/wood-fired boiler at U.S. Sugar's Clewiston mill. However, these applications have been for new units in which the SNCR design was integrated into the design of the new unit. In addition, the "uncontrolled" NO_X emissions rates have been much higher than predicted by the applicant for the No. 4 Combination Boiler. For example, U.S. Sugar's Boiler 8 has an uncontrolled NO_X emissions rate of approximately 0.32 lb/MMBtu and uses an urea-based Fuel Tech SNCR system with a control efficiency of more than 50% to reduce NO_X emissions to 0.14 lb/MMBtu. For the No. 4 Combination Boiler, the same vendor indicated a control efficiency of only 30%.

The applicant submitted additional information (dated May 25, 2007) indicating that a NO_X emissions rate of 0.22 lb/MMBtu may be achievable with a new OFA system based on information from a vendor, Jansen Combustion and Boiler Technologies (Jansen). However, the applicant later indicated that Jansen was reluctant to provide a performance guarantee. The applicant requested that the Department hold issuance of the draft permit until additional testing could be performed. Based on five tests, NO_X emissions ranged from 0.215 to 0.277 lb/MMBtu for various combinations of wood and oil. The single test on wood alone indicated emissions of 0.241 lb/MMBtu. In a letter dated May 2, 2008, Jansen indicated the following concerns:

- The proposed project will increase the maximum heat input rate from wood firing and improve overall combustion. This may increase furnace temperatures and NO_X emissions.
- Jansen believes that fuel NO_X contributes more to NO_X emissions than thermal NO_X for this emissions unit. The nitrogen content of the bark/wood at the Georgia-Pacific Palatka Mill was tested to be 0.91% by weight on a dry basis. This contrasts with an average value of 0.53% by weight on a dry basis from Jansen's data for wood samples. This means that the fuel NO_X contribution for boilers at Georgia-Pacific may be higher than for other wood-fired boilers.

[2] "Assessment of Control Technology Options for BART-Eligible Sources, Steam Electric Boilers, Industrial Boilers, Cement Plants and Pulp and Paper Facilities", Northeast States for Coordinated Air Use Management, March 2005.

- Based on the limited data, Jansen predicts a NO_X emissions rate of 0.26 lb/MMBtu for the upgraded boiler with OFA system.

Although the Department considered this recent information, it is based on a limited amount of additional data. Based on a review of all available information, the Department establishes the following draft NO_X BACT standards:

As determined by CEMS data, NO_X emissions shall not exceed 0.24 lb/MMBtu and 135.4 lb/hour when firing bark/wood based on a 30-day rolling average. See discussion below.

As determined by CEMS data, NO_X emissions shall not exceed 0.27 lb/MMBtu and 113.0 lb/hour when firing residual oil based on a 30-day rolling average.

As determined by CEMS data, NO_X emissions shall not exceed 0.15 lb/MMBtu and 64.1 lb/hour when firing natural gas based on a 30-day rolling average.

The BACT standards are based on an OFA system, combustion controls and low-NO_X burner system for natural gas firing. Emissions data collected during startup, shutdown and malfunction may be excluded from the compliance demonstration. When more than one fuel is fired, the emissions standard shall be prorated based on the heat input rate of each fuel. Eventually, residual oil will be phased out for natural gas.

The applicant expressed concerns regarding possibly higher than expected uncontrolled NO_X emissions and the ability of the OFA system to achieve the previously requested NO_X limits for bark/wood of 0.24 and subsequently 0.22 lb/MMBtu based on the earlier Jansen prediction. In consideration, the permit authorizes an initial interim NO_X standard of 0.28 lb/MMBtu for the first consecutive 12 months after completing work (including a 90 calendar day shakedown period) on the bark/wood fuel delivery system and the OFA system. The initial interim period provides time to gather emissions data with the CEMS and adjust the OFA system as necessary to comply with the NO_X BACT standard of 0.24 lb/MMBtu. If unable to comply with the NO_X BACT standard of 0.24 lb/MMBtu based on the new OFA system, the permit requires installation of additional NO_X control equipment (e.g., selective non-catalytic reduction system, etc.) to comply with a standard of 0.17 lb/MMBtu. The new control equipment must be installed and operating before the end of the initial interim period.

CEMS Installations

To control particulate matter, exhaust from the modified boiler will be split into two streams, each with separate multiclones/ESP/stacks. To demonstrate compliance with the particulate matter standards, tests must be conducted simultaneously on each stack. For CO and NO_X emissions, the draft permit requires the installation of CEMS to demonstrate compliance with the emissions standards for CO and NO_X. Since these pollutants are gases and the standards (lb/MMBtu) are based on the heat input rate of the fuel being fired, the Department will allow the installation of CEMS on one stack to represent emissions from the boiler. Mass emissions will be determined by installing flow rate monitors or use of the appropriate F-factors for each fuel.

4. AIR QUALITY IMPACT 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.

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 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.

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

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

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

The proposed project will increase emissions of the following pollutants in excess of the PSD significant emissions rates: CO, NO_X, PM_{10} and VOC. Based on the netting analysis and permit restrictions, SO_2 emissions avoid PSD preconstruction review for the project.

Preconstruction Ambient Monitoring Analysis

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

De Minimis Air Quality Levels				
Pollutant	**Averaging Time**	**Maximum Predicted Impact (μg/m³)**	**De Minimis Concentration (μg/m³)**	**Greater than De Minimis?**
CO	8-hr	79	575	No
NO_2	Annual	2	14	No
PM_{10}	24-hr	12	10	Yes

As shown above, CO and NO_2 are exempt from preconstruction monitoring because the predicted impacts are less than the de minimis levels. However, PM_{10} is not exempt from preconstruction ambient monitoring. In addition, the project results in PSD net emissions increases of 502 tons/year of NO_2 and 426 tons/year of VOC, which are each 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 2003 to 2007 available for existing nearby monitoring locations.

Representative Ambient Concentrations			
Pollutant	Averaging Time	Ambient Concentration	Monitor Location
CO	8-hour	3220 μg/m^3	Jacksonville
	1-hour	4255 μg/m^3	Jacksonville
NO_2	Annual	27 μg/m^3	Jacksonville
Ozone	8-hour	68 ppbv	Gainesville
PM_{10}	Annual	26 μg/m^3	Palatka
	24-hour	68 μg/m^3	Palatka

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 CO, NO_2, ozone and PM_{10}. As necessary, the above ambient concentrations will be used as the ambient background concentrations for any required AAQS analysis.

The applicant and the Department discussed available options for potentially predicting ambient ozone impacts caused by the NO_2 and VOC emissions increases (ozone precursor pollutants) 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 kilometers 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 are greater than 50 kilometers from the proposed facility, long-range transport modeling was required for the PSD Class I impact assessment.

PSD Class I Area	Distance	Receptors
Okefenokee NWA	108 km	180
Chassahowitzka NWA	137 km	113
Wolf Island NWA	186 km	30

Meteorological Data for PSD Class I Analysis

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

Results of PSD Class I Significant Impact Analysis

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

Significant Impact Analysis for PSD Class I Areas					
Pollutant	Averaging Time	Maximum Predicted Impact (μg/m^3)	Significant Impact Level (μg/m^3)	Significant Impact?	Affected Class I Area
NO_2	Annual	0.003	0.1	No	Okefenokee NWA
PM_{10}	Annual	0.001	0.2	No	Okefenokee NWA
	24-hour	0.01	0.3	No	Okefenokee NWA

As shown, the maximum predicted impacts are less than the corresponding significant impact levels for each pollutant. 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 Jacksonville International 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.

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/m³)**	**Significant Impact Level (µg/m³)**	**Significant Impact?**	**Radius of Significant Impact (km)**
PM_{10}	Annual	1.4	1	Yes	1
	24-hr	12	5	Yes	1
CO	8-hr	67	500	No	N/A
	1-hr	79	2,000	No	N/A
NO_2	Annual	2	1	Yes	1

As shown above, the predicted CO impacts are well below the corresponding PSD Class II significant impact levels and no further analysis for CO is required. The predicted PM_{10} and NO_2 impacts are greater than the corresponding PSD Class II significant impact levels; therefore, a full impact analysis for these pollutants is required within the applicable significant impact area as defined by the predicted radius of significant impact identified above. For PM_{10} and NO_2 emissions, a PSD Class II increment analysis and an AAQS analysis was 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 PM_{10} and NO_2 were 1 kilometer or less. However, the applicant placed over 2000 receptors along the restricted property line of the facility and 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 and PM_{10} 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	3	25	No
PM_{10}	Annual	0	17	No
	24-hour	22	30	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 NO_2 and PM_{10}.

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?
PM_{10}	Annual	11	26	37	50	No
	24-hour	42	79	121	150	No
NO_2	Annual	10	27	37	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 PM_{10}, NO_X and CO 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 maximum predicted nitrogen deposition rates are below the threshold levels recommended by the federal land manager.

Conclusion on Air Quality Impacts

As described in this report and based on the required 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.

5. CONCLUSION

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 documents. Cleve Holladay is the staff meteorologist responsible for reviewing the ambient air quality analyses. Jeff Koerner is the Air Permitting Supervisor responsible for reviewing and editing the draft permit package. 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

Georgia-Pacific Consumer Operations LLC
Post Office Box 919
Palatka, Florida 32178-0919

Authorized Representative:
Mr. Keith Wahoske, Vice President

Air Permit No. PSD-FL-393
Project No. 1070005-045-AC
Georgia-Pacific Palatka Mill
No. 4 Combination Boiler Modifications
SIC Nos. 2611 and 2621
Permit Expires: July 1, 2011

FACILITY AND LOCATION

This permit authorizes several physical modifications to the No. 4 Combination Boiler. The proposed work will be conducted at the existing Palatka Mill, which is a paper and pulp mill. The facility is located North of County Road 216 and West of U.S. Highway 17 in Palatka, Putnam County, Florida. The map coordinates are: UTM Zone 17; 434.0 km East; and 3283.4 km North.

STATEMENT OF BASIS

This air pollution construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.), and Part 63 of Title 40 of the Code of Federal Regulations (CFR). Specifically, the project is subject to the preconstruction requirements for the Prevention of Significant Deterioration (PSD) of Air Quality in accordance with Rule 62-212.400, F.A.C. The permittee is authorized to install the proposed equipment in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department of Environmental Protection (Department).

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(Draft)

Joseph Kahn, Director
Division of Air Resource Management

Effective Date

FACILITY AND PROJECT DESCRIPTION

The Georgia-Pacific Consumer Operations LLC operates an existing pulp and paper mill in Palatka, Florida. The existing mill uses the Kraft sulfate process in which 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 furnace 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 process the green liquor to cooking liquor. Steam and energy needs are met by the combination, power and recovery boilers, which burn a variety of fuels including carbonaceous fuel, BLS, fuel oil and natural gas. Products of incomplete combustion include carbon monoxide (CO), nitrogen oxides (NO_X), particulate matter (PM), particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers (PM_{10}), sulfuric acid mist (SAM), sulfur dioxide (SO_2), total reduced sulfur (TRS) and volatile organic compounds (VOC).

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

Current Project

The No. 4 Combination Boiler (EU-016) will be modified in two phases. The initial phase includes the following changes: upgrading the bark/wood delivery system with new air swept bark conveyors and feed bin to increase bark/wood firing rate; increasing the maximum hourly heat input rate; installation of a new overfire air (OFA) system; installing new mechanical collectors to replace the existing multiclone pre-cleaners; installing a bottom ash handling system; modifying the ductwork to use the existing multiclones/electrostatic precipitator (ESP)/stack from the No. 5 Power Boiler (which has been converted to natural gas) to serve the No. 4 Combination Boiler in parallel with the existing multiclones/ESP/stack; and modifying the ductwork to introduce the dilute noncondensible gases (DNCG) into the new OFA system. The second phase will convert the supplemental residual oil firing system for No. 4 Combination Boiler to natural gas and permanently discontinue use of residual oil. Implementing this phase is dependent on obtaining additional pipeline capacity from the natural gas vendor, the Florida Gas Transmission Company, which may take approximately two to three years depending on the siting process for new pipelines as well as construction.

Based on a netting analysis including other contemporaneous projects, this project is subject to PSD preconstruction review for emissions of CO, NO_X, PM_{10} and VOC in accordance with Rule 62-212.400, F.A.C. The permit establishes emissions standards for these pollutants based on the Best Available Control Technologies (BACT) as determined by the Department. Particulate matter emissions will be controlled with new mechanical collectors and an improved ESP system. Emissions of CO, NO_X and VOC will be controlled by improving overall combustion and staging combustion with the upgraded OFA system. Low-NO_X burners will be installed to further reduce NO_X emissions when firing natural gas. Continuous emissions monitoring systems (CEMS) are required for CO and NO_X to demonstrate compliance, which will also provide feedback to the control system and operators.

Previous Projects

Based on the following previous projects, the No. 4 Combination Boiler is currently authorized to operate as a control device in the following circumstances.

- Pursuant to previous air construction Permit No. 1070005-017-AC, the No. 4 Combination Boiler is authorized to serve as a backup destruction device to the Thermal Oxidizer (EU-037) for noncondensible gases (NCG) and condensate stripper off-gases (SOG) from the sources subject to Subpart S (MACT I) of 40 CFR 63 and Rule 62-296.404, F.A.C., for TRS emissions. Prior to destruction in the boiler, a spray tower pre-scrubber removes sulfur compounds from the batch digesting system and a separate spray tower pre-scrubber removes sulfur compounds from the multiple effect evaporator system streams. Operation as a backup destruction device would occur during startup, shutdown and malfunctions of the Thermal Oxidizer. The boiler is permitted to operate as the backup destruction device for a maximum uptime of 20%. These provisions also include a requirement to continuously monitor the combustion zone temperature with a thermocouple in lieu of monitoring TRS emissions.
- Pursuant to previous air construction Permit No. 1070005-024-AC, the No. 4 Combination Boiler is authorized to destroy DNCG from the from the brown stock washer system and associated pressure knotters and screens. The No. 5 Power Boiler serves as a backup unit to the No. 4 Combination Boiler for the destruction of DNCG.

These provisions are specified in the latest Title V air operation permit (No. 1070005-048-AV). This project does not impose any new applicable requirements for operation as a control device.

1. Permitting Authority. The Permitting Authority for this project is the Bureau of Air Regulation in the Department's Division of Air Resource Management. The mailing address for the Bureau of Air Regulation is 2600 Blair Stone Road, MS #5505, Tallahassee, Florida 32399-2400. All documents related to applications for permits to operate an emissions unit shall be submitted to Department's Northeast District office.

2. Compliance Authority. All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Department's Northeast District office. The mailing address and phone number of the Department of Environmental Protection, Northeast District, Air Resources, 7825 Baymeadows Way, Suite 200B, Jacksonville, Florida 32256-7590. The District telephone number is 904/807-3300 and facsimile number is 904/448-4363.

3. Appendices. The following Appendices are attached as an enforceable part of this permit:

    a. Appendix A. Citation Formats and Glossary of Common Terms.

    b. Appendix B. General Conditions.

    c. Appendix C. Common Conditions.

    d. Appendix D. Standard Testing Requirements.

    e. Appendix E. Summary of Best Available Control Technology Determinations.

    f. Appendix F. Standard Continuous Monitoring Requirements.

    g. 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 unit. 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. Depending on the timing of Phase 2 of this project, it may be necessary to submit an application to revise the Title V permit after completing the Phase 1 work and later apply for a revision to include the Phase 2 work. 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 appropriate Permitting Authority with copies to each Compliance Authority. [Rules 62-4.030, 62-4.050, 62-4.220, and Chapter 62-213, F.A.C.]

A. No. 4 Combination Boiler (EU-016)

This section of the permit addresses the following emissions unit.

No. 4 Combination Boiler (EU-016)
The boiler is a spreader-stoker traveling grate furnace with a pneumatic fuel feed distribution system. It was manufactured by Babcock & Wilcox and constructed in 1965. The primary fuel is bark/wood, which is supplemented with fuel oil. This project will replace supplemental fuel oil with natural gas. The maximum steam production rate is 475,000 lb/hour based on steam conditions of 900° F at 1275 psi. Particulate matter emissions are controlled by mechanical dust collectors as pre-cleaners to the ESP. The boiler also serves as a backup control device for other permitted operations. The unit continuously monitors TRS emissions. This project will add CO and NO_X CEMS.

EXISTING APPLICABLE REGULATIONS

1. Existing Permits and Regulations: This permit supplements other previously issued air permits for the No. 4 Combination Boiler, which include the following applicable state and federal regulations.

   a. Pursuant to Rule 62-296.404(3)(a)1, F.A.C., the No. 4 Combination Boiler is subject to the applicable requirements for a combustion device incinerating TRS emissions at a Kraft pulp mill.

   b. Pursuant to Rule 62-296.410(1)(b), F.A.C., the No. 4 Combination Boiler is subject to the applicable requirements for an existing carbonaceous fuel fired boiler.

   c. Pursuant to 40 CFR 63.443(d)(4)(ii), the No. 4 Combination Boiler is subject to the applicable requirements for controlling HAP emissions from the pulping system at Kraft processes. [NESHAP Subpart S in 40 CFR 63]

   {Permitting Note: The applicable requirements are specified in the latest Title V air operation permit (No. 1070005-048-AV). This project does not impose any new applicable requirements from these existing regulations.} [Rules 62-296.404 and 62-296.410, F.A.C.; and 40 CFR 63.443]

MODIFICATIONS AND CAPACITIES

2. Modifications – Phase 1: The permittee shall make the following modifications and other related work to the No. 4 Combination Boiler:

   a. Upgrade the bark/wood waste fuel delivery system by replacing worn out feed system parts, replacing the existing bark surge bin, modifying conveyors to accommodate these changes, and installing new air swept bark distributors;

   b. Install a new OFA system with multiple levels of combustion air;

   c. Modify the DNCG piping for incorporation into the new OFA system;

   d. Replace existing multiclones with a new mechanical dust collector; and

   e. Modify the ductwork to use the existing multiclones/ESP/stack from the No. 5 Power Boiler (EU-015, which has been converted to fire only natural gas) to connect in parallel service with the new mechanical dust collector/existing ESP/existing stack for the No. 4 Combination Boiler.

   The purpose of this phase is to improve overall combustion, increase the maximum hourly heat input rate for bark/wood firing, improve equipment reliability and reduce NO_X and PM emissions. These modifications shall be complete prior to operating at the higher heat input rates authorized by this permit. The permittee shall begin construction on this phase within 18 months of issuance of this permit. [Rules 62-4.070(3) and 62-212.400(12), F.A.C., and Application No. 1070005-045-AC (PSD-FL-393)]

6. Modifications – Phase 2: The permittee is authorized to make the following modifications to the No. 4

Combination Boiler and other related work:

a. Install low-NO_X burners with a natural gas distribution system; and

b. Connect to the natural gas supply line for continuous operation.

The natural gas vendor, the Florida Gas Transmission Company, estimates that it may take approximately two to three years to add the necessary capacity to the pipeline for this project. Therefore, the permittee shall commence construction on this phase of the project within 18 months of July 1, 2010. Once the boiler is fully functional on natural gas, the boiler is prohibited from firing fuel oil. [Rules 62-4.070(3) and 62-212.400(12), F.A.C., and Application No. 1070005-045-AC (PSD-FL-393)]

7. PM Control Equipment: On each exhaust stream, the permittee shall install, operate and maintain mechanical dust collectors and an ESP to control PM emissions. The following table summarizes the main preliminary control equipment parameters for these systems.

Parameter	**Exhaust 1** [a]	**Exhaust 2** [b]
Pre-Cleaner		
Type	Mechanical Dust Collectors	Mechanical Dust Collectors
Inlet Temperature	700° F	700° F
Exhaust Flow Rate	280,000 acfm	280,000 acfm
Pressure Drop	< 3 inches of w.c.	< 3 inches of w.c.
Control Efficiency	80% - 90%	80% - 90%
ESP		
Manufacturer	Research Cottrell	Research Cottrell
Type	Plate/Rigid Mast Electrodes	Plate/Rigid Mast Electrodes
Configuration	2 chambers, 3 fields	2 chambers, 3 fields
Pressure	Positive	Positive
T/R Sets	6 T/R sets per field	6 T/R sets per field
Inlet Temperature	325° F	325° F
Exhaust Flow Rate	230,000 acfm	230,000 acfm
Control Efficiency	99.5%	99.5%
Stack		
Diameter	8.0 feet	7.1 feet
Height	237 feet	237 feet
Exhaust Flow	158,500 acfm	158,500acfm
	67,700 dscfm @ 10% O_2	67,700 dscfm @ 10% O_2
Exhaust Temperature	500° F	500° F

a. This exhaust stream includes the mechanical dust collector, ESP and stack originally constructed with the No. 4 Combination Boiler.

b. This exhaust stream includes the mechanical dust collector, ESP and stack originally constructed with the No. 5 Power Boiler.

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

8. Authorized Fuels: After completing Phase 1 of the modifications, the No. 4 Combination Boiler is authorized to fire the following fuels: bark/wood, No. 6 residual fuel oil with a maximum sulfur content of 2.35% by weight, and natural gas (startup fuel). On-specification used oil generated on site and meeting the fuel sulfur specification may be fired with No. 6 fuel oil. See Appendix G for conditions specific to on-specification used oil. Once construction is complete on Phase 2 (addition of natural gas), the permittee is prohibited from firing fuel oil and on-specification used oil. *{Permitting Note: As described in the project description in Section 1 of this permit, the No. 4 Combination Boiler was previously permitted to serve as a control device to combust NCG, SOG and DNCG.}* [Rules 62-210.200(PTE) and 62-212.400(PSD), F.A.C.; Permit Nos. 1070005-017-AC and 1070005-024-AC]

9. Permitted Capacity: After completing the modifications, the No. 4 Combination Boiler is authorized to operate at the following maximum heat input rates.

Fuel Source	Maximum Heat Input Rate
Bark/Wood (alone or combined with other fuels)	564.0 MMBtu/hr, 24-hr average [a]
Residual Fuel Oil	418.6 MMBtu/hr, 24-hr average [b]
Natural Gas	427.0 MMBtu/hr, 24-hr average [c]

[a] Based of 59.4 tons per hour of bark/wood with an average heating value of 4750 Btu/lb on an as-fired basis (wet).

[b] Based of 2791 gallons per hour No. 6 fuel oil with an average heating value of 150,000 Btu/gallon.

[c] Based of 427,000 cubic feet (cf) per hour of natural gas with an average heating value of 1000 Btu/cf.

[Rule 62-210.200(PTE), F.A.C.; Permit Nos. 1070005-024-AC and 1070005-028-AC; and Application No. 1070005-045-AC (PSD-FL-393)]

10. Operational Restrictions: The hours of operation of No. 4 Combination Boiler are not limited (8760 hours per year). However, operation shall not exceed the following restrictions.

    a. No more than 5,100,000 gallons of No. 6 fuel oil shall be fired during any consecutive 12-month rolling total. *{Permitting Note: This requirement will become obsolete after completion of the Phase 2 work and the cessation of oil firing.}*

    b. The total heat input rate shall not exceed 4,042,127 MMBtu during any consecutive 12-month rolling total.

    The permittee shall keep records on a monthly basis to ensure compliance with these operational restrictions. [Rules 62-210.200(PTE) and 62-212.400(PSD), F.A.C.; Permit No. PSD-FL-380; and Application No. 1070005-045-AC (PSD-FL-393)]

EMISSIONS STANDARDS

{Permitting Note: The following standards apply to the No. 4 Combination Boiler (EU-016). Unless otherwise specified for standards demonstrated by stack test, the actual emission rate shall be the arithmetic average of three separate test runs. See Rules 62-297.310(1), (2) and (3), F.A.C.]}

11. CO Emissions: When firing any combination of authorized fuel, CO emissions shall not exceed 0.50 lb/MMBtu and 282.0 lb/hour based on a 30-day rolling CEMS average. This standard excludes authorized periods of startup, shutdown and malfunction. [Rules 62-212.400(BACT) and 62-4.070(3), F.A.C.]

12. NOx Emissions:

    a. *Bark/Wood*: During the initial interim period, NO_X emissions shall not exceed 0.28 lb/MMBtu and 157.9 lb/hour based on a 30-day rolling CEMS average. The initial interim period is defined as the first consecutive 12 months after completing work (including a 90 calendar day shakedown period) on the bark/wood fuel delivery system and the OFA system. During the initial interim period, the permittee shall operate the boiler and control system to minimize NO_X emissions to the extent practicable. Thereafter, one of the following standards shall apply. Day 1 of the first 30-day rolling average compliance period for the new standard is the first day after the end of the 12 month initial interim period.

        (1) NO_X emissions shall not exceed 0.24 lb/MMBtu and 135.4 lb/hour based on a 30-day rolling CEMS average. This standard applies following the initial interim period defined above in Condition 12.a based on satisfactory reductions achieved by the installed OFA system.

        (2) If unable to achieve the NO_X emissions standard specified above in Condition 12.a(1) based solely on the installed OFA system, the permittee shall complete the requirements in paragraphs (a) and (b) before the end of the initial interim period defined above.

            (a) The permittee shall provide notification that an additional NO_X control system will be installed. The notification shall include the preliminary design details of the selected control system and a schedule for installation and commencement of operation.

            (b) The permittee shall install, operate and maintain a NO_X control system (e.g., selective non-catalytic reduction system) to comply with a NO_X emissions standard of 0.17 lb/MMBtu and 95.9 lb/hour based on a 30-day rolling CEMS average.

    b. *Fuel Oil*: When firing only No. 6 fuel oil, NO_X emissions shall not exceed 0.27 lb/MMBtu and 113.0 lb/hour based on a 30-day rolling CEMS average.

    c. *Natural Gas*: When firing only natural gas, NO_X emissions shall not exceed 0.15 lb/MMBtu and 64.1 lb/hour based on a 30-day rolling CEMS average.

    d. *Combinations of Fuels*: When firing a combination of fuels, the NO_X emissions standard shall be prorated based on the heat input rate from each fuel actually fired.

    These standards exclude authorized periods of startup, shutdown and malfunction. [Rules 62-212.400(BACT) and 62-4.070(3), F.A.C.]

13. PM Emissions:

    a. *PM Emissions*: When firing any authorized fuel or combination thereof, PM emissions shall not exceed 0.030 lb/MMBtu and 16.9 lb/hour as determined by tests conducted in accordance with EPA Method 5 or 29.

    b. *Opacity*: When firing any authorized fuel or combination thereof, visible emissions shall not exceed 20% opacity based on a 6-minute average, except for one 6-minute period per hour that shall not exceed 27% opacity, as determined by EPA Method 9. This standard applies to each stack.

    {Permitting Note: Compliance with these standards ensures compliance with the applicable standards of Rule 62-296.410(1)(b), F.A.C. for Carbonaceous Fuel Burning Equipment.} [Rules 62-212.400(BACT) and 62-296.410, F.A.C.]

14. VOC Emissions: When firing any authorized fuel or combination thereof, VOC emissions shall not exceed 0.02 lb/MMBtu and 11.3 lb/hour as determined by EPA Method 25A stack testing. Initial compliance shall be demonstrated while firing bark/wood at permitted capacity. Thereafter, compliance shall be assumed if

the unit remains in compliance with the CO standards demonstrated by CEMS. [Rule 62-212.400(BACT), F.A.C.]

CONTINUOUS EMISSIONS COMPLIANCE MONITORING

15. Compliance by CEMS: Compliance with the CO and NO_X standards shall be demonstrated with data collected from the CEMS required by this permit. The permittee shall properly install, calibrate, operate and maintain CEMS to measure and record CO and NO_X emissions in the terms of each applicable standard. The systems shall include continuous monitors to determine the flue gas oxygen or carbon dioxide content and exhaust flow rate. Each CEMS shall be installed such that representative measurements of emissions or process parameters from the facility are obtained. The permittee shall comply with the conditions in Appendix F (Standard Continuous Monitoring Requirements) of this permit. Each CEMS shall be installed, certified, fully operational and collecting compliance data within 90 days of achieving the new permitted capacity on bark/wood, but no later than 180 days after completing the work on the bark/wood fuel delivery system and the OFA system. If emissions are representative, the permittee may monitor only one of the two stacks to determine CO and NO_X emissions based on an approved CEMS Operation Plan as required in Appendix F of this permit. [Rules 62-212.400(BACT) and 62-4.070(3), F.A.C.]

COMPLIANCE TESTING REQUIREMENTS

16. 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. [Rule 62-297.310, F.A.C.]

17. 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.]

18. Test Methods: Compliance tests shall be conducted in accordance with the following EPA Reference Methods as described in Appendix A of 40 CFR 60, and adopted by reference in Rule 62-204.800, F.A.C.

EPA Method	Description of Method and Comments
1-4	Methods for Determining Traverse Points, Velocity and Flow Rate, Gas Analysis, and Moisture Content: These methods shall be performed as necessary to support other methods.
5 or 29	Methods for Determining Particulate Matter Emissions
7E	Method for Determining Nitrogen Oxides Emissions
9	Visual Determination of the Opacity of Emissions from Stationary Sources
10	Method for Determining Carbon Monoxide Emissions (Instrumental): The method shall be based on a continuous sampling train.
18	Method for Measuring Gaseous Organic Compound Emissions by Gas Chromatography EPA Method 18 may be conducted simultaneously with EPA Method 25A to deduct non-regulated methane emissions from regulated VOC emissions.
25A	Method for Determining Total Gaseous Organic Concentration using a Flame Ionization Analyzer

No other methods may be used unless prior written approval is received from the Department. [Rules 62-212.400(BACT), 62-204.800 and 62-297.310, F.A.C.; and Appendix A of 40 CFR 60]

19. Compliance Tests: In accordance with the following requirements, the permittee shall have stack tests conducted to demonstrate compliance with the emissions standards specified in this permit.

a. *Initial Tests*: The permittee shall conduct initial tests to demonstrate compliance with the emissions standards for opacity, PM and VOC. After completing modifications of the bark/wood feeder and OFA systems, the permittee shall conduct initial tests within 90 calendar days of achieving permitted capacity, but no later than 180 calendar days after initial startup.

b. *Subsequent Tests*: During each federal fiscal year (October 1st to September 30th), the permittee shall conduct tests to determine compliance with the emissions standards for shall be conducted for opacity, PM and VOC. If initial tests show satisfactory compliance with the VOC standards, compliance with the CO standards will serve as a surrogate for demonstrating compliance with the VOC standards and annual VOC tests will not be required unless requested by the Department as a special test pursuant to Rule 62-297.310(7)(b), F.A.C.

c. *Test Fuel*: All tests shall be conducted when firing only bark/wood at permitted capacity.

d. *Simultaneous PM Stack Testing*: Exhaust from the No. 4 Combination Boiler is split into two streams with separate PM control devices. Therefore, the permittee shall conduct simultaneous stack tests on the two stacks to determine compliance with the PM emissions standard. Each performance test shall consist of three runs. [Rules 62-4.070(3) and 62-221.400(BACT), F.A.C.]

e. *Operational Data for Tests*: For each test run, the permittee shall monitor and record the following information: fuel feed rate; the heat input rate; the secondary power input to each ESP; the flue gas oxygen or carbon dioxide content (%); and CO and NO_X CEMS data (when available).

Compliance with the CO and NO_X standards shall be demonstrated by data collected from the required CEMS. [Rules 62-212.400(BACT) and 62-297.310, F.A.C.]

EXCESS EMISSIONS

20. Excess Emissions: Pursuant to Rules 62-210.700(5) and 62-212.400, F.A.C., the Department establishes the following conditions related to excess emissions.

a. Compliance with the CO and NO_X standards are determined by data collected with required CEMS excluding authorized periods of startup, shutdown and malfunction. The permittee may exclude CEMS data collected during the following authorized periods as limited by this condition.

1. *Startup*: No more than eight hours of CEMS data may be excluded for any startup.
2. *Shutdown*: No more than eight hours of CEMS data may be excluded for any shutdown.
3. *Malfunction*: No more than two hours of CEMS data in any 24-hour period may be excluded for malfunction.

Appendix F of this permit defines the terms "startup, shutdown and malfunction" and specifies other continuous monitoring requirements.

b. The No. 4 Combination Boiler shall comply with the opacity standards once the ESP is placed in service during a startup in accordance with the manufacturer's recommendations. If best operational practices are used to minimize the magnitude and duration of emissions, excess opacity resulting from malfunction is allowed for no more than two hours in any 24-hour period.

The above requirements are established in lieu of the provisions in Rule 62-210.700(1), F.A.C. [Rules 62-210.700 and 62-212.400(BACT), F.A.C.]

MONITORING REQUIREMENTS

21. Fuel Monitoring: The permittee shall continuously monitor the following:

a. *Bark/Wood*: The permittee shall monitor and record the amount of bark/wood (tons) fired and the equivalent heat input rate (MMBtu) to demonstrate compliance with the conditions of this permit.

b. *Fuel Oil*: The permittee shall install, operate and maintain an oil flow monitoring system to demonstrate compliance with the conditions of this permit.

c. *On-Specification Used Oil*: The permittee shall monitor and record the amount of on-specification used oil fired. The permittee shall comply with the requirements in Appendix G (On-Specification Used Oil Requirements) of this permit.

d. *Natural Gas*: The permittee shall install, operate and maintain a natural gas flow monitoring system to demonstrate compliance with the conditions of this permit.

e. *Heat Input Rate*: The permittee shall record the total equivalent heat input rate (MMBtu) to demonstrate compliance with the conditions of this permit.

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

22. Fuel Oil Sulfur Records: The sulfur content of the No. 6 fuel oil used by the facility for all of the fuel sources shall not exceed 2.35% by weight based on a 3-barge rolling average. A record of analysis of each fuel oil shipment received shall be maintained and an annual report submitted. In order to demonstrate compliance with this condition, the permittee shall calculate and maintain a log of the rolling 3-barge average sulfur content (i.e., the average of three consecutive barge deliveries based on the certified fuel oil analysis receipt). Fuel oil analysis shall be conducted using ASTM Methods D-129, D-1552, D-2622, D-4294, or equivalent methods approved by the Department. The Annual Report is due by April 1st for the previous year. [Rules 62-212.400(BACT), 62-4.070(3) and 62-297.440, F.A.C.]

23. Steam Records: The permittee shall continuously monitor and record the following steam parameters: steam production rate (lb/hour), steam pressure (psig) and steam temperature (° F). [Rules 62-212.400(BACT) and 62-4.070(3), F.A.C.]

RECORDS AND REPORTS

24. Test Reports: The permittee shall prepare and submit reports for all required tests in accordance with the requirements specified in Appendix D (Standard Testing Requirements) of this permit. For each test run, the report shall also indicate the amount of fuel fired and the equivalent heat input rate. [Rules 62-4.070(3) and 62-297.310(8), F.A.C.]

25. Semiannual Monitoring Reports: The permittee shall submit a written report to the Compliance Authority summarizing the following for each calendar quarter: CO and NO_X emissions; CEMS monitor availability; bark/wood fuel fired; gallons of fuel oil fired; cubic feet of natural gas fired; and total hours of operation. The reports shall identify any exceedance of an emissions or performance limitation. The reports are due within 30 days following the second and fourth calendar quarters. [Rules 62-4.070(3) and 62-213.440(1)(b)3., F.A.C.; and 1070005-045-AC/PSD-FL-393]

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 signifi9cant 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 (X);
    b. Determination of Prevention of Significant Deterioration (X); and
    c. Compliance with New Source Performance Standards (not 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 two hours in any 24 hour period unless specifically authorized by the Department for longer duration. [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 Department or the appropriate Local Program 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.]

{Permitting Note: Rule 62-210-700(Excess Emissions), F.A.C. cannot vary or supersede any federal provision of the New Source Performance Standards (NSPS) or the National Emission Standards for Hazardous Air Pollutants (NESHAP) programs.}

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. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating rates and emissions from this facility. Annual operating reports shall be submitted to the Compliance Authority by March 1st of each year. [Rule 62-210.370(3), 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.]

SECTION 4. APPENDIX E

SUMMARY OF BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATIONS

PROJECT DESCRIPTION

Georgia-Pacific Consumer Operations LLC operates an existing paper and pulp mill in Palatka using the Kraft sulfate process. 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 furnace 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. Other steam and energy needs are met by the power boilers, which burn a variety of fuels including bark/wood, residual fuel oil and natural gas.

The No. 4 Combination Boiler will be modified in two phases. The initial phase includes the following changes: upgrades to the bark/wood delivery system with new air swept bark conveyors and feed bin to increase bark/wood firing rate; increase the maximum hourly heat input rate; installation of a new overfire air (OFA) system; installation of a new mechanical collector to replace the existing multiclone pre-cleaner; installation of a bottom ash handling system; modification of ductwork to use the existing multiclone/electrostatic precipitator (ESP)/stack from the No. 5 Power Boiler (which has been converted to natural gas) to serve the No. 4 Combination Boiler in parallel with the existing multiclone/ESP/stack; and modification of ductwork to introduce the dilute non-condensible gases into the new OFA system. The second phase will convert the supplemental residual oil firing system for the No. 4 Combination Boiler to natural gas and permanently discontinue use of residual oil. Implementing this phase is dependent on obtaining additional pipeline capacity from the natural gas vendor, the Florida Gas Transmission Company, which may take approximately 2 to 3 years depending on the siting process for new pipelines as well as construction.

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 with an aerodynamic mean diameter equal to or less than 10 microns (PM_{10}) and volatile organic compounds (VOC) in accordance with Rule 62-212.400, F.A.C. Contemporaneous emissions decreases allowed the project to avoid PSD preconstruction review for the emissions of sulfur dioxide (SO_2), sulfuric acid mist (SAM) and total reduced sulfur compounds. PM emissions serve as a surrogate for regulating PM_{10} emissions. Conversion from supplemental fuel oil to natural gas will result in a potential reduction of more than 3800 tons/year of SO_2 and 163 tons/year of SAM.

SUMMARY OF BACT DETERMINATIONS

The following table summarizes the BACT standards for this project.

Pollutant	BACT Standards	Control Technology	Monitoring
PM (all fuels)	$\leq$0.030 lb/MMBtu and 16.9 lb/hour	dual multiclone-ESP combinations in parallel and OFA system	initial and annual tests EPA Method 5 or 29, 3-test run average
VE (all fuels)	$\leq$ 20% opacity based on 6-minute averages, except for one 6-minute period per hour $\leq$27% opacity		initial and annual tests EPA Method 9, one-hour observations
NO_X Bark/Wood Oil Gas	 $\leq$0.24 lb/MMBtu and 135.4 lb/hour [c] $\leq$0.27 lb/MMBtu and 113.0 lb/hour $\leq$0.15 lb/MMBtu and 64.1 lb/hour	improved OFA system, combustion controls, low-nitrogen fuels and LNB system for gas	30-day rolling CEMS average [a] (standard prorated based on heat input rate from each fuel)
CO (all fuels)	0.50 lb/MMBtu and 282.0 lb/hour	improved OFA system and combustion controls	30-day rolling CEMS average [a]
VOC (all fuels)	0.02 lb/MMBtu and 11.3 lb/hour	improved OFA system and combustion controls	initial test [b] EPA Method 25A, 3-test run average

a. The CO and NO_X standards include all periods of operation except startup, shutdown and malfunction.

b. EPA Method 18 may be conducted simultaneously with EPA Method 25A to deduct methane emissions. If initial VOC tests show satisfactory compliance, compliance with the CO standards will serve as a surrogate for compliance.

c. The permit authorizes an initial interim NO_X standard of 0.28 lb/MMBtu for the first consecutive 12 months after completing work (including a 90 calendar day shakedown period) of the new systems on the bark/wood fuel delivery system and the OFA system. The interim period provides time to gather emissions data and adjust the OFA system to comply with the NO_X BACT standard of 0.24 lb/MMBtu. If unable to comply with the NO_X BACT standard of 0.24 lb/MMBtu based on the new OFA system, the permit requires installation of additional NO_X control equipment (e.g., selective non-catalytic reduction system, etc.) to comply with a standard of 0.17 lb/MMBtu. The new control equipment must be installed and operating before the end of the initial interim period.

STANDARD CONTINUOUS MONITORING REQUIREMENTS

The No. 4 Combination Boiler (EU-016) is 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 plan shall also address the location of a single CO and NO_X CEMS that would provide representative emissions from both exhaust stacks. 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. Exhaust gas from the No. 4 Combination Boiler is split into two separate streams with separate PM control devices. Since CO and NO_X are gases and the standards are based on the heat input rate of the fuel being fired (lb/MMBtu), the permittee may install the CEMS on one stack as long as emissions are representative from the emissions unit.

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: If required by permit to correct the CEMS output to the oxygen concentrations specified in the applicable emissions standard, the permittee shall either install an oxygen (O_2) monitor or a carbon dioxide (CO_2) monitor and use an appropriate F-Factor computational approach. [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 CEMS 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, shutdown and malfunction 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. See Condition 20 in Subsection 4A of the permit for authorized periods of data exclusion. 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, shutdown and malfunction 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, shutdown or malfunction). 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. Specifications for Used Oil: Only "on-specification" used oil containing a PCB concentration of less than 50 ppm shall be fired at this facility.

   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. Used Oil Certifications: For each delivery of used oil, the owner or operator shall receive from the marketer a certification that the used oil meets the specifications for "on-specification" used oil and that it contains a PCB concentration of less than 50 ppm. This certification shall also describe the basis for the certification, such as analytical results. Used oil to be fired for energy recovery is presumed to contain quantifiable levels (2 ppm) of PCB unless the marketer obtains analyses (testing) or other information that the used oil fuel does not contain quantifiable levels of PCBs. Note that a claim that used oil does not contain quantifiable levels of PCBs (<2 ppm) must be documented by analysis or other information. The first person making the claim that the used oil does not contain PCBs is responsible for furnishing the documentation. The documentation can be tests, personal or special knowledge of the source and composition of the used oil, or a certification from the person generating the used oil claiming that the used oil contains no detectable PCBs. [40 CFR 761.20]

3. Notification to Marketers: Before accepting from each marketer the first shipment of on-specification used oil with a PCB concentration of 2 to less than 50 ppm, the owner or operator shall provide each marketer with a one-time written and signed notice certifying that the owner or operator will fire the used oil in a qualified combustion device and must identify the class of combustion device. The notice must state that EPA or a RCRA-delegated state agency has been given a description of the used oil management activities at the facility and that an industrial boiler or furnace will be used to fire the used oil with a PCB concentration of 2 to 49 ppm. The description of the used oil management activities may be submitted to the Administrator, Hazardous Waste Regulation Section, Florida Department of Environmental Protection, 2600 Blair Stone Road, Tallahassee, FL 32399-2400. [and 40 CFR 761.20(e)]

4. Sampling and Analysis:

   a. If the owner or operator does not receive certification from the marketer as described above, the owner or operator shall sample and analyze each batch of used oil to be fired for the following parameters: arsenic, cadmium, chromium, lead, total halogens, flash point, PCBs, and percent sulfur content by weight, ash, and BTU value (BTU per gallon).

b. If the owner or operator receives the required certification from the marketer, the owner or operator shall sample at least one delivery of used oil received each calendar quarter and analyze the sample for arsenic, cadmium, chromium, lead, total halogens, flash point, PCBs, and percent sulfur content by weight, ash, and BTU value (BTU per gallon).

c. 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.

d. 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]

5. 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 received and fired during the previous calendar month and the previous 12 calendar months.

   b. The name and address of all marketers delivering used oil to the facility.

   c. Copies of the marketer certifications and any supporting information.

   d. If claimed, documentation that the used oil contains less than 2 ppm of PCBs, including the name and address of the person making the claim.

   e. Results of any sampling/analyses conducted.

   f. A copy of the notice to EPA and a copy of the one-time written notice provided to each marketer.

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

6. Used Oil Reporting Required: Within 30 days following each calendar quarter, the owner or operator shall submit to the appropriate Compliance Authority, the analytical results and the total amount of on-specification used oil received and fired during the quarter. [Rule 62-4.070(3), F.A.C.; 40 CFR Parts 279 and 761]

Harvey, Mary

From: Harvey, Mary

Sent: Friday, May 09, 2008 2:53 PM

To: 'Mr. Keith Wahoske, Georgia-Pacific Consumer Operations LLC'; 'Mr. Mike Curtis, Georgia-Pacific Consumer Operations LLC'; 'Mr. Mark Aguilar, P.E., Georgia-Pacific Consumer Operations LLC'; 'Mr. Wayne Galler, Georgia-Pacific Consumer Operations LLC'; 'Mr. David Buff, P.E., Golder Associates, Inc.'; 'Mr. Chris Kirts, Northeast District Office'; 'Ms. Katy Forney, U.S. EPA, Region 4'; 'Mr. Dee Morse, National Park Service'

Cc: Mitchell, Bruce; Walker, Elizabeth (AIR); Gibson, Victoria

Subject: Draft Air Permit No. PSD-FL-393 - Project #1070005-045-AC - Georgia-Pacific Consumer Operation LLC - Palatka Mill

Attachments: Document.pdf; PSD-FL-393 - Appendices.PDF; PSD-FL-393 - Draft Permit.PDF; PSD-FL-393 - Intent.PDF; PSD-FL-393 - Public Notice.PDF; PSD-FL-393 - TEPD.PDF

Tracking:

Recipient	Delivery	Read
'Mr. Keith Wahoske, Georgia-Pacific Consumer Operations LLC'		
'Mr. Mike Curtis, Georgia-Pacific Consumer Operations LLC'		
'Mr. Mark Aguilar, P.E., Georgia-Pacific Consumer Operations LLC'		
'Mr. Wayne Galler, Georgia-Pacific Consumer Operations LLC'		
'Mr. David Buff, P.E., Golder Associates, Inc.'		
'Mr. Chris Kirts, Northeast District Office'		
'Ms. Katy Forney, U.S. EPA, Region 4'		
'Mr. Dee Morse, National Park Service'		
Mitchell, Bruce	Delivered: 5/9/2008 2:53 PM	
Walker, Elizabeth (AIR)	Delivered: 5/9/2008 2:53 PM	
Gibson, Victoria	Delivered: 5/9/2008 2:53 PM	Read: 5/9/2008 2:54 PM

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Harvey, Mary

From: Mitchell, Bruce

Sent: Friday, May 09, 2008 3:09 PM

To: Harvey, Mary

Cc: Walker, Elizabeth (AIR)

Subject: RE: Draft Air Permit No. PSD-FL-393 - Project #1070005-045-AC - Georgia-Pacific Consumer Operation LLC - Palatka Mill

Thanks, Mary, very much for handling the processing this project. Take care and have a great day (what's left of it) and week!!!!!!!

Bruce

From: Harvey, Mary
Sent: Friday, May 09, 2008 2:53 PM
To: 'Mr. Keith Wahoske, Georgia-Pacific Consumer Operations LLC'; 'Mr. Mike Curtis, Georgia-Pacific Consumer Operations LLC'; 'Mr. Mark Aguilar, P.E., Georgia-Pacific Consumer Operations LLC'; 'Mr. Wayne Galler, Georgia-Pacific Consumer Operations LLC'; 'Mr. David Buff, P.E., Golder Associates, Inc.'; 'Mr. Chris Kirts, Northeast District Office'; 'Ms. Katy Forney, U.S. EPA, Region 4'; 'Mr. Dee Morse, National Park Service'
Cc: Mitchell, Bruce; Walker, Elizabeth (AIR); Gibson, Victoria
Subject: Draft Air Permit No. PSD-FL-393 - Project #1070005-045-AC - Georgia-Pacific Consumer Operation LLC - Palatka Mill

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Thank you,

DEP, Bureau of Air Regulation

Harvey, Mary

From: Galler, Wayne J. [WJGALLER@GAPAC.com]
To: Harvey, Mary
Sent: Friday, May 09, 2008 2:54 PM
Subject: Read: Draft Air Permit No. PSD-FL-393 - Project #1070005-045-AC - Georgia-Pacific Consumer Operation LLC - Palatka Mill

Your message

To: WJGALLER@GAPAC.com
Subject:

was read on 5/9/2008 2:54 PM.

Harvey, Mary

From: Gibson, Victoria
To: Harvey, Mary
Sent: Friday, May 09, 2008 2:57 PM
Subject: Read: FW: Draft Air Permit No. PSD-FL-393 - Project #1070005-045-AC - Georgia-Pacific Consumer Operation LLC - Palatka Mill

Your message

To: Gibson, Victoria
Subject: FW: Draft Air Permit No. PSD-FL-393 - Project #1070005-045-AC - Georgia-Pacific Consumer Operation LLC - Palatka Mill
Sent: 5/9/2008 2:54 PM

was read on 5/9/2008 2:57 PM.

Harvey, Mary

From: Galler, Wayne J. [WJGALLER@GAPAC.com]
To: Harvey, Mary
Sent: Friday, May 09, 2008 2:54 PM
Subject: Read: Draft Air Permit No. PSD-FL-393 - Project #1070005-045-AC - Georgia-Pacific Consumer Operation LLC - Palatka Mill

Your message

To: WJGALLER@GAPAC.com
Subject:

was read on 5/9/2008 2:54 PM.

Harvey, Mary

From: Kirts, Christopher
To: Harvey, Mary
Sent: Friday, May 09, 2008 3:33 PM
Subject: Read: FW: Draft Air Permit No. PSD-FL-393 - Project #1070005-045-AC - Georgia-Pacific Consumer Operation LLC - Palatka Mill

Your message

To:	Kirts, Christopher
Subject:	FW: Draft Air Permit No. PSD-FL-393 - Project #1070005-045-AC - Georgia-Pacific Consumer Operation LLC - Palatka Mill
Sent:	5/9/2008 3:23 PM

was read on 5/9/2008 3:33 PM.

Harvey, Mary

From: Gibson, Victoria
To: Harvey, Mary
Sent: Friday, May 09, 2008 2:54 PM
Subject: Read: Draft Air Permit No. PSD-FL-393 - Project #1070005-045-AC - Georgia-Pacific Consumer Operation LLC - Palatka Mill

Your message

To: 'Mr. Keith Wahoske, Georgia-Pacific Consumer Operations LLC'; 'Mr. Mike Curtis, Georgia-Pacific Consumer Operations LLC'; 'Mr. Mark Aguilar, P.E., Georgia-Pacific Consumer Operations LLC'; 'Mr. Wayne Galler, Georgia-Pacific Consumer Operations LLC'; 'Mr. David Buff, P.E., Golder Associates, Inc.'; 'Mr. Chris Kirts, Northeast District Office'; 'Ms. Katy Forney, U.S. EPA, Region 4'; 'Mr. Dee Morse, National Park Service'
Cc: Mitchell, Bruce; Walker, Elizabeth (AIR); Gibson, Victoria
Subject: Draft Air Permit No. PSD-FL-393 - Project #1070005-045-AC - Georgia-Pacific Consumer Operation LLC - Palatka Mill
Sent: 5/9/2008 2:53 PM

was read on 5/9/2008 2:54 PM.

Harvey, Mary

From: Wahoske, Keith [KEITH.WAHOSKE@GAPAC.com]

Sent: Friday, May 09, 2008 3:58 PM

To: Harvey, Mary; Curtis, Michael; Aguilar, Mark J.; Galler, Wayne J.; Mr. David Buff, P.E., Golder Associates, Inc.; Mr. Chris Kirts, Northeast District Office; Ms. Katy Forney, U.S. EPA, Region 4; Mr. Dee Morse, National Park Service

Cc: Mitchell, Bruce; Walker, Elizabeth (AIR); Gibson, Victoria

Subject: RE: Draft Air Permit No. PSD-FL-393 - Project #1070005-045-AC - Georgia-Pacific Consumer Operation LLC - Palatka Mill

We are in receipt of your Email

Thank you

Keith Wahoske

-----Original Message-----
From: Harvey, Mary [mailto:Mary.Harvey@dep.state.fl.us]
Sent: Friday, May 09, 2008 2:53 PM
To: Wahoske, Keith; Curtis, Michael; Aguilar, Mark J.; Galler, Wayne J.; Mr. David Buff, P.E., Golder Associates, Inc.; Mr. Chris Kirts, Northeast District Office; Ms. Katy Forney, U.S. EPA, Region 4; Mr. Dee Morse, National Park Service
Cc: Mitchell, Bruce; Walker, Elizabeth (AIR); Gibson, Victoria
Subject: Draft Air Permit No. PSD-FL-393 - Project #1070005-045-AC - Georgia-Pacific Consumer Operation LLC - Palatka Mill

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Thank you,

DEP, Bureau of Air Regulation

Harvey, Mary

From: Curtis, Michael [MICHAEL.CURTIS@GAPAC.com]
To: Harvey, Mary
Sent: Friday, May 09, 2008 4:02 PM
Subject: Read: Draft Air Permit No. PSD-FL-393 : Project #1070005-045-AC - Georgia-Pacific Consumer Operation LLC - Palatka Mill

Your message

To: MICHAEL.CURTIS@GAPAC.com
Subject:

was read on 5/9/2008 4:02 PM.

Harvey, Mary

From: Buff, Dave [DBuff@GOLDER.com]
To: undisclosed-recipients
Sent: Friday, May 09, 2008 6:45 PM
Subject: Read: Draft Air Permit No. PSD-FL-393 - Project #1070005-045-AC - Georgia-Pacific Consumer Operation LLC - Palatka Mill

Your message

To: DBuff@GOLDER.com
Subject:

was read on 5/9/2008 6:45 PM.

Harvey, Mary

From: Forney.Kathleen@epamail.epa.gov
Sent: Monday, May 12, 2008 10:50 AM
To: Harvey, Mary
Subject: Re: Draft Air Permit No. PSD-FL-393 - Project #1070005-045-AC - Georgia-Pacific Consumer Operation LLC - Palatka Mill

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>

05/09/2008 02:52 PM

To
"Mr. Keith Wahoske, Georgia-Pacific Consumer Operations LLC" <keith.wahoske@gapac.com>, "Mr. Mike Curtis, Georgia-Pacific Consumer Operations LLC" <michael.curtis@gapac.com>, "Mr. Mark Aguilar, P.E., Georgia-Pacific Consumer Operations LLC" <mjaguila@gapac.com>, "Mr. Wayne Galler, Georgia-Pacific Consumer Operations LLC" <wjgaller@gapac.com>, "Mr. David Buff, P.E., Golder Associates, Inc." <dbuff@golder.com>, "Mr. Chris Kirts, Northeast District Office" <Christopher.Kirts@dep.stste.fl.us>, Kathleen Forney/R4/USEPA/US@EPA, "Mr. Dee Morse, National Park Service" <dee_morse@nps.gov>

cc
"Mitchell, Bruce" <Bruce.Mitchell@dep.state.fl.us>, "Walker, Elizabeth \(AIR\)" <Elizabeth.Walker@dep.state.fl.us>, "Gibson, Victoria" <Victoria.Gibson@dep.state.fl.us>

Subject
Draft Air Permit No. PSD-FL-393 - Project #1070005-045-AC - Georgia-Pacific Consumer Operation LLC - Palatka Mill

Harvey, Mary

From: Dee_Morse@nps.gov
Sent: Monday, May 12, 2008 6:31 PM
To: Harvey, Mary
Subject: Draft Air Permit No. PSD-FL-393 - Project #1070005-045-AC - Georgia-Pacific Consumer Operation LLC - Palatka Mill

Return Receipt

Your document:	Draft Air Permit No. PSD-FL-393 - Project #1070005-045-AC - Georgia-Pacific Consumer Operation LLC - Palatka Mill
was received by:	Dee Morse/DENVER/NPS
at:	05/12/2008 04:29:41 PM MDT