Friday, Barbara

From: Harvey, Mary
Sent: Monday, April 16, 2007 1:21 PM
To: Adams, Patty
Subject: FW: Georgia-Pacific Consumer Operation LLC - Palatka Mill - Facility ID # 1070005-038-AC-DRAFT

Intent 4/13/07

-----Original Message-----
From: Dee_Morse@nps.gov [mailto:Dee_Morse@nps.gov]
Sent: Monday, April 16, 2007 11:51 AM
To: Harvey, Mary
Subject: Georgia-Pacific Consumer Operation LLC - Palatka Mill - Facility ID # 1070005-038-AC-DRAFT

Return Receipt

Your document:	Georgia-Pacific Consumer Operation LLC - Palatka Mill - Facility ID # 1070005-038-AC-DRAFT
was received by:	Dee Morse/DENVER/NPS
at:	04/16/2007 09:51:22 AM MDT

Friday, Barbara

From: Harvey, Mary

Sent: Monday, April 16, 2007 9:14 AM

To: Adams, Patty

Subject: FW: Georgia-Pacific Consumer Operation LLC - Palatka Mill - Facility ID # 1070005-038-AC-DRAFT

From: Wahoske, Keith [mailto:KEITH.WAHOSKE@GAPAC.com]
Sent: Friday, April 13, 2007 5:40 PM
To: Harvey, Mary
Subject: RE: Georgia-Pacific Consumer Operation LLC - Palatka Mill - Facility ID # 1070005-038-AC-DRAFT

Ms. Harvey:

We are in receipt of your Email dated 4/13/07

Thank you

Keith Wahoske

-----Original Message-----
From: Harvey, Mary [mailto:Mary.Harvey@dep.state.fl.us]
Sent: Friday, April 13, 2007 3:48 PM
To: Wahoske, Keith; Curtis, Michael; Aguilar, Mark J.; Mr. David Buff, P.E., Golder Associates, Inc.; Mr. Chris Kirts, Northeast District Office; Mr. Dee Morse, National Park Service
Cc: Mitchell, Bruce; Koerner, Jeff; Adams, Patty; Gibson, Victoria
Subject: Georgia-Pacific Consumer Operation LLC - Palatka Mill - Facility ID # 1070005-038-AC-DRAFT

Dear Sir/Madam:

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

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

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

The Bureau of Air Regulation is issuing electronic documents for permits, notices and other correspondence in lieu of hard copies through the United States Postal System, to provide greater service to the applicant and the engineering community. Please advise this office of any changes to your e-mail address or that of the Engineer-of-Record.

Thank you,

DEP, Bureau of Air Regulation

Friday, Barbara

From: Harvey, Mary
Sent: Friday, April 13, 2007 3:50 PM
To: 'little.james@epamail.epa.gov'
Cc: Mitchell, Bruce; Koerner, Jeff; Adams, Patty
Subject: FW: Georgia-Pacific Consumer Operation LLC - Palatka Mill - Facility ID # 1070005-038-AC-DRAFT
Attachments: Appendix - PSD-FL-380 - FACILITY #1070005-038-AC-DRAFT.PDF; Draft Permit - PSD-FL-380 - FACILITY #1070005-038-AC-DRAFT.PDF; PSD-FL-380 - Intent to Issue - FACILITY #1070005-038-AC-DRAFT.PDF; SIGNED DOCUMENTS FOR PERMIT #1070005-038-AC-DRAFT.pdf; TEPD - 1070005-038-AC - FACILITY #1070005-038-AC-DRAFT.PDF

From: Harvey, Mary
Sent: Friday, April 13, 2007 3:48 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. David Buff, P.E., Golder Associates, Inc.'; 'Mr. Chris Kirts, Northeast District Office'; 'Mr. Dee Morse, National Park Service'
Cc: Mitchell, Bruce; Koerner, Jeff; Adams, Patty; Gibson, Victoria
Subject: Georgia-Pacific Consumer Operation LLC - Palatka Mill - Facility ID # 1070005-038-AC-DRAFT

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Thank you,

DEP, Bureau of Air Regulation

Friday, Barbara

From: Harvey, Mary
Sent: Friday, April 13, 2007 4:24 PM
To: Adams, Patty
Subject: FW: Georgia-Pacific Consumer Operation LLC - Palatka Mill - Facility ID # 1070005-038-AC-DRAFT

From: Curtis, Michael [mailto:MICHAEL.CURTIS@GAPAC.com]
Sent: Friday, April 13, 2007 4:17 PM
To: Harvey, Mary
Subject: Read: Georgia-Pacific Consumer Operation LLC - Palatka Mill - Facility ID # 1070005-038-AC-DRAFT

Your message

To: MICHAEL.CURTIS@GAPAC.com
Subject:

was read on 4/13/2007 4:17 PM.

Friday, Barbara

From: Harvey, Mary

Sent: Friday, April 13, 2007 3:48 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. David Buff, P.E., Golder Associates, Inc.'; 'Mr. Chris Kirts, Northeast District Office'; 'Mr. Dee Morse, National Park Service'

Cc: Mitchell, Bruce; Koerner, Jeff; Adams, Patty; Gibson, Victoria

Subject: Georgia-Pacific Consumer Operation LLC - Palatka Mill - Facility ID # 1070005-038-AC-DRAFT

Attachments: 1070005.038.AC.D_pdf.zip

Dear Sir/Madam:

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The Bureau of Air Regulation is issuing electronic documents for permits, notices and other correspondence in lieu of hard copies through the United States Postal System, to provide greater service to the applicant and the engineering community. Please advise this office of any changes to your e-mail address or that of the Engineer-of-Record.

Thank you,

DEP, Bureau of Air Regulation

Memorandum

Florida Department of
Environmental Protection

TO: Trina Vielhauer, Chief - Bureau of Air Regulation

THROUGH: Jeff Koerner, Air Permitting North

FROM: Bruce Mitchell

DATE: April 13, 2007

SUBJECT: Draft Air Permit No. PSD-FL-380
Project No. 1070005-038-AC
Georgia-Pacific Consumer Operations LLC
Modifications to the Nos. 4 Lime Kiln, Recovery Boiler and Multiple Effect Evaporators, and the No. 5 Power 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

P.E. CERTIFICATION STATEMENT

APPLICANT

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

Project No. 1070005-038-AC
Permit No. PSD-FL-380
PSD Modification
Palatka Mill
Putnam County, Florida

PROJECT DESCRIPTION

Georgia-Pacific operates an existing Kraft sulfate process pulp and paper mill located North of County Road 216 and West of U.S. Highway 17 in Palatka, Putnam County, Florida. This permit authorizes the following major modifications: permanent shutdown of the No. 4 Power Boiler; conversion of the No. 5 Power Boiler to natural gas; replacement of the hot-end section and cooler tubes for the No. 4 Lime Kiln; extensive tube replacement and modification of the combustion air system (including the addition of a fourth level of overfire air) for the No. 4 Recovery Boiler; and the addition of a crystallizer with associated storage/flash tank and modifications to the two concentrators associated with the No. 4 multiple effect evaporator set.

The permittee conducted a PSD netting analysis based on contemporaneous emissions increases and decreases to avoid PSD preconstruction review for SO_2, SAM, and TRS. The project is subject to PSD preconstruction review for CO, NO_X, PM, and VOC. For this permit, the Department determined the Best Available Control Technology (BACT) for the following units: the No. 5 Power Boiler (CO and VOC); the No. 4 Lime Kiln (CO, NO_X, PM, and VOC); and the No. 4 Recovery Boiler (CO, NO_X, PM, and VOC). The No. 4 Combination Boiler is currently under PSD preconstruction review in Project No. 1070005-045-AC for CO, NO_X, PM, and VOC.

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

Jeffery F. Koerner — 4-13-07

Jeffery F. Koerner, P.E.
Registration No. 49441

(Date)

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

April 13, 2007

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

Re: Draft Air Permit No. PSD-FL-380
Project No. 1070005-038-AC
Georgia-Pacific Consumer Operations LLC – Palatka Mill
Request to Modify the Nos. 4 Lime Kiln, Recovery Boiler and Multiple Effect Evaporators, and the No. 5 Power Boiler

Dear Mr. Wahoske:

On July 18, 2006, Georgia-Pacific Consumer Operations LLC submitted an application to modify the Nos. 4 Lime Kiln, Recovery Boiler and Multiple Effect Evaporators, and the No. 5 Power Boiler at the Palatka Mill, which is located North of CR 216 and West of US 17, Palatka, Putnam County, 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 Technical Evaluation and Preliminary Determination summarizes the Bureau of Air Regulation's technical review of the application and provides the rationale for making the preliminary determination to issue a draft permit. The proposed Draft Permit includes the specific conditions that regulate the emissions units covered by the proposed project. The Written Notice of Intent to Issue Air Permit provides important information regarding: the Permitting Authority's intent to issue an air permit for the proposed project; the requirements for publishing a Public Notice of the Permitting Authority's intent to issue an air permit; the procedures for submitting comments on the Draft Permit; the process for filing a petition for an administrative hearing; and the availability of mediation. 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, Chief
Bureau of Air Regulation

Enclosures

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 – Palatka Operations

Draft Air Permit No. PSD-FL-380
Project No. 1070005-038-AC
Palatka Mill
Modifications of the Nos. 4 Lime Kiln, Recovery Boiler and Multiple Effect Evaporators, and the No. 5 Power 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 Nos. 4 Lime Kiln, Recovery Boiler and Multiple Effect Evaporators, and the No. 5 Power Boiler. Details of the project are provided in the application and the enclosed "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 of the Florida Administrative Code (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 Rule 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 Draft Permit for a period of 30 days from the date of publication of the Public Notice. Written comments must be post-marked by the close of business (5:00 p.m.), on or before the end of this 30-day period by the Permitting Authority at the above address. As part of his or her comments, any person may also request that the Permitting Authority hold a public meeting on this permitting action. If the Permitting Authority determines there is sufficient interest for a public meeting, it will publish notice of the time, date, and location in the Florida Administrative Weekly and in a newspaper of general circulation in the area affected by the permitting action. For additional information, contact the Permitting Authority at the above address or phone number. If written comments or comments received at a public meeting result in a significant change to the Draft Permit, the Permitting Authority will issue a Revised 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

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 4/13/07 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. David Buff, P.E., Golder Associates, Inc. (dbuff@golder.com)
Mr. Chris Kirts, Northeast District Office (chris.kirts@dep.state.fl.us)
Mr. Jim Little, U.S. EPA, Region 4 (little.james@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 — 4/13/07
(Clerk) (Date)

PUBLIC NOTICE OF INTENT TO ISSUE AIR PERMIT

Florida Department of Environmental Protection
Bureau of Air Regulation
Project No. 1070005-038-AC/Draft Air Permit No. PSD-FL-380
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 – 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 Nos. 4 Lime Kiln, Recovery Boiler and Multiple Effect Evaporators, and the No. 5 Power Boiler. The project will result in the following potential emissions increases: 1473 tons/year of carbon monoxide (CO); 405 tons/year of nitrogen oxides (NO_X); 105 tons/year of particulate matter (PM); 84 tons/year of particulate matter with an aerodynamic diameter of 10 microns or less (PM_{10}); 4.2 tons/year of sulfuric acid mist; and 418 tons/year of volatile organic compounds (VOC). The project includes conversion of the No. 5 Power Boiler from a primary fuel of residual oil to natural gas. This will result in a reduction of more than 3400 tons per year of sulfur dioxide. Pursuant to Rule 62-212.400, F.A.C., the project is subject to preconstruction review for the prevention of significant deterioration (PSD) of air quality for emissions of CO, NO_X, PM, PM_{10}, and VOC. The draft permit establishes emissions standards for these pollutants based on the Best Available Control Technologies as determined by the Department.

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 NO_2, SO_2, and PM_{10} consumed by all sources in the area, including this project, will be as follows:

PSD Class II Increment

	Consumed ($\mu g/m^3$)	Allowable ($\mu g/m^3$)	Percent Consumed
PM_{10}			
24-hour	22	30	73
Annual	0	17	0
SO_2			
3-hour	125	512	24
24-hour	60	91	66
Annual	8	20	40
NO_2			
Annual	3	25	12

NO_2 and PM_{10} emissions from the project have no significant impact on the PSD Class I Okefenokee National Wilderness Area (NWA), the Chassahowitzka NWA and Wolf Island NWA The maximum predicted PSD Class I increments of SO_2 consumed in these Class I areas by all sources, including this project, will be as follows:

PSD Class I Increment

	Consumed ($\mu g/m^3$)	Allowable ($\mu g/m^3$)	Percent Consumed
SO_2			
3-hour	24.4	25	98
24-hour	4.14	5	83
Annual	0	2	0

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 of the Florida Administrative Code (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.

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Comments: The Permitting Authority will accept written comments concerning the Draft Permit for a period of 30 days from the date of publication of the Public Notice. Written comments must be post-marked by the close of business (5:00 p.m.), on or before the end of this 30-day period by the Permitting Authority at the above address. As part of his or her comments, any person may also request that the Permitting Authority hold a public meeting on this permitting action. If the Permitting Authority determines there is sufficient interest for a public meeting, it will publish notice of the time, date, and location in the Florida Administrative Weekly and in a newspaper of general circulation in the area affected by the permitting action. For additional information, contact the Permitting Authority at the above address or phone number. If written comments or comments received at a public meeting result in a significant change to the Draft Permit, the Permitting Authority will issue a Revised Draft Permit and require, if applicable, another Public Notice. All comments filed will be made available for public inspection.

Petitions: A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative hearing in accordance with Sections 120.569 and 120.57, F.S. The petition must contain the information set forth below and must be filed with (received by) the Department's Agency Clerk in the Office of General Counsel of the Department of Environmental Protection, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000 (Telephone: 850/245-2241; Fax: 850/245-2303). Petitions filed by any persons other than those entitled to written notice under Section 120.60(3), F.S., must be filed within 14 days of publication of this Public Notice or receipt of a written notice, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the Permitting Authority for notice of agency action may file a petition within 14 days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above, at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57, F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention (in a proceeding initiated by another party) will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205, F.A.C.

A petition that disputes the material facts on which the Permitting Authority's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner; the name, address and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of when and how each petitioner received notice of the agency action or decision; (d) A statement of all disputed issues of material fact; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action including an explanation of how the alleged facts relate to the specific rules or statutes; and, (g) A statement of the relief sought by the petitioner, stating precisely the action the petitioner wishes the agency to take with respect to the agency's proposed action. A petition that does not dispute the material facts upon which the Permitting Authority's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Permitting Authority's final action may be different from the position taken by it in this 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.

TECHNICAL EVALUATION

AND

PRELIMINARY DETERMINATION

PROJECT

Draft Permit No. 1070005-038-AC (PSD-FL-380)
Georgia-Pacific Palatka Mill
Facility ID No. 1070005
Modification of the No. 5 Power Boiler, No. 4 Lime Kiln, and No. 4 Recovery Boiler

COUNTY

Putnam County, Florida

APPLICANT

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

PERMITTING AUTHORITY

Florida Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation - Air Permitting North
2600 Blair Stone Road, MS #5505
Tallahassee, FL 32399-2400

April 13, 2007

1. GENERAL PROJECT INFORMATION

Facility and Location

The Georgia-Pacific Consumer Operations LLC operates an existing pulp and paper mill (SIC Nos. 2611 and 2621) in Palatka located North of CR 216 and West of US 17, Putnam County, Florida. The UTM coordinates of this facility are: Zone 17; 434.0 km East; and, 3283.4 km North. This site is in an area that is in attainment (or designated as unclassifiable) for each air pollutant subject to a National Ambient Air Quality Standard (NAAQS).

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 power boilers, which burn a variety of fuels including fuel oil and natural gas. The recovery boiler, lime kiln, and power boiler all fire fuels and produce products of incomplete combustion, including 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). On the following page, Figure 10.2-1 shows the typical process flow for a Kraft sulfate pulping and recovery process.

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.
- The facility is a major stationary source subject to the Prevention of Significant Deterioration (PSD) of Air Quality.

Project Description

The applicant requests an air construction permit for the following modifications to the existing pulp and paper mill.

No. 5 Power Boiler (EU-015): Currently, the No. 5 Power Boiler fires residual oil with a maximum sulfur content of 2.35% by weight. This boiler is the largest source of SO_2 emissions at the plant and is considered an eligible unit subject to Rule 62-296.340, F.A.C. for the Best Available Retrofit Technology (BART). In conjunction with this PSD project and the BART program, the No. 5 Power Boiler will be completely converted to fire natural gas as the sole fuel. This modification results in large reductions of SAM and SO_2 emissions to avoid PSD preconstruction review for the project and also satisfy the program requirements for BART. Since the unit will be limited only to gaseous fuel, the existing electrostatic precipitator will be removed.

No. 4 Lime Kiln (EU-017). Approximately 62 feet of the hot-end kiln shell and all ten coolers located in this section will be replaced. The new coolers will be mounted with an improved bracket design to prevent stress cracks underneath the coolers. The total cost of the lime kiln project is estimated at $1.8 million.

No. 4 Recovery Boiler (EU-018) and No. 4 Multiple Effect Evaporator Set (EU-032): The applicant proposes numerous physical changes to the recovery boiler, including:

- Extensive replacement of tubes will be made in the superheater, economizer, main generating banks and floor. The tube replacements are not considered routine because the original tubes have been in place since the unit was originally constructed in the 1970s. The estimated cost for re-tubing the boiler is $24 million.
- Physical changes will be made to the combustion air system to lower the peak furnace exhaust gas temperature and velocity into the superheater. This effort is intended to reduce potential corrosion and pluggage of the superheater. The modified air system is also expected to reduce PM/PM_{10} carry over and fouling in the boiler convection tube banks. By staging the combustion air, an increase in boiler efficiency is anticipated, which may reduce some pollutants due to better combustion (i.e., CO, PM/PM_{10}, and TRS), but may result in slight increases in NO_X. To offset the potential emissions increase in nitrogen oxides, the applicant proposes to install a fourth level of combustion air (quaternary air) to provide

additional staged combustion. The capacity of the No. 4 Recovery Boiler will remain unchanged at 789,000 lbs/hr of steam for a 24-hour average based on steam conditions of 850° F to 900° F at 1250 psi. The maximum fuel firing rate of 210,000 lbs/hour of BLS will not change. The estimated cost to modify the combustion air system is less than $2 million.

- The black liquor evaporator system, specifically the No. 4 Multiple Effect Evaporator (MEE) set, will be modified to increase the concentration of BLS from 65% to 75%. The purpose of the modification is to improve the combustion efficiency of the No. 4 Recovery Boiler by reducing the amount of water in the BLS being fired. A crystallizer vessel will be installed to remove additional moisture from black liquor leaving the concentrators. The crystallizer will increase the temperature of the black liquor, which will discharge into a storage/flash tank at a lower pressure to "flash-off" the liquid water to a vapor. The vapor will be routed to the existing evaporator system and collected as part of the existing non-condensable gas (NCG) collection system. The applicant expects to fire less supplemental fuel oil by improving the firing of BLS. Increasing the recovery boiler efficiency should reduce the steam demand for other existing boilers that fire fuel oil. However, the increased solids content may result in increased particulate loading to the exhaust flue gas. The estimated cost to modify the black liquor evaporator system is $5 to $6 million.
- In the existing concentrators, some internal baffles will be removed and several downcomer piping resized. This effort will improve liquor circulation and increase velocity through the tubes, which should reduce scaling and fouling as well as the frequency of "boil outs", which reduces component life. An external heat exchanger will be added to the existing concentrators to preheat the black liquor with steam prior to entering the concentrators, which will improve evaporation. The changes will allow the fuel feed system to more closely match the existing capacity of the No. 4 Recovery Boiler. Emissions generated from the external heat exchanger will be controlled by the existing NCG collection system.

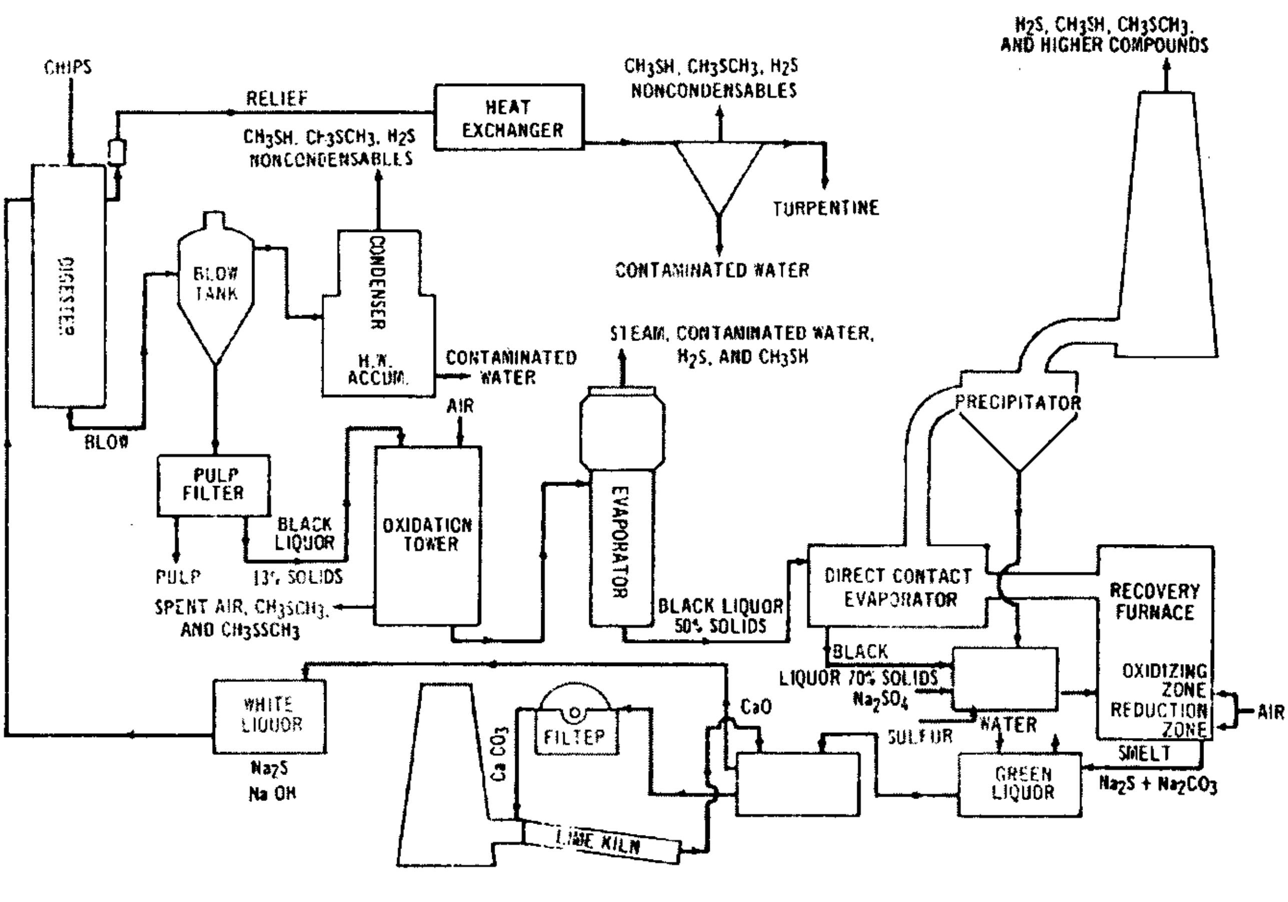

Figure 10.2-1. Typical kraft sulfate pulping and recovery process.

Reference: Section 10.2, Chemical Wood Pulping, AP 42, Fifth Edition, *Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources*, September 1990.

Proposed Schedule

Excluding the cost of converting the No. 5 Power Boiler to natural gas, the total cost of the project is estimated to be approximately $32 million. The preliminary schedule is to complete all of the work except for the crystallizer project during the June/July 2007 outage. It is likely that construction on the crystallizer project will not begin until some time in 2008.

Reviewing and Processing Schedule

July 18, 2006: Receipt of application;

August 17, 2006: Request for additional information;

September 29, 2006: Receipt of additional information;

October 27, 2006: Request for additional information;

November 16, 2006: Receipt of additional information;

December 15, 2006: Request for additional information;

February 5, 2007: Receipt of additional information, but still incomplete per response #1;

March 15, 2007: Receipt of additional information;

March 16, 2007: Receipt of additional information; and

April 5, 2007: Receipt of additional information.

2. RULE APPLICABILITY

State Regulations

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.). This project is subject to the rules and regulations defined in the following generally applicable Chapters of the F.A.C.: 62-4 (Permitting Requirements); 62-204 (Ambient Air Quality Requirements, PSD Increments, and Federal Regulations Adopted by Reference); 62-210 (Permits Required, Public Notice, Reports, Stack Height Policy, Circumvention, Excess Emissions, and Forms); 62-212 (Preconstruction Review, PSD Review and BACT); 62-213 (Title V Air Operation Permits for Major Sources of Air Pollution); 62-296 (Emission Limiting Standards); and 62-297 (Test Methods and Procedures, Continuous Monitoring Specifications, and Alternate Sampling Procedures). The affected emissions units are subject to the following industry-specific regulations:

- Rule 62-296.404, F.A.C. for Kraft pulp mills;
- Rule 62-296.405, F.A.C. for fossil fuel steam generators with more than 250 MMBtu per hour of heat input; and
- Rule 62-212.400, F.A.C. for PSD preconstruction review.

The existing permits capture the applicable provisions for Rules 62-296.404 and 62-296.405, F.A.C. These requirements will not be repeated for this project.

Federal Regulations

The Environmental Protection Agency establishes air quality regulations in Title 40 of the Code of Federal Regulations (CFR). Part 60 identifies New Source Performance Standards (NSPS) for a variety of industrial activities. Part 61 specifies the National Emissions Standards for Hazardous Air Pollutant (NESHAP) based on specific pollutants. Part 63 identifies NESHAPs 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. Specifically, emissions units at the mill are subject to the following federal regulations:

- 40 CFR 60, NSPS Subpart A for the general provisions;
- 40 CFR 60, NSPS Subpart Db for industrial boilers;
- 40 CFR 60, NSPS Subpart Kb for petroleum storage tanks;
- 40 CFR 60, NSPS BB for Kraft pulp mills;
- 40 CFR 63, NESHAP Subpart A for the general provisions;

- 40 CFR 63, NESHAP Subpart S for Kraft pulp mills;
- 40 CFR 63, NESHAP Subpart MM for Kraft pulp mills;
- 40 CFR 63, NESHAP Subpart RR for individual drain systems;
- 40 CFR 63, NESHAP Subpart JJJJ for core manufacturing activities at pulp and paper mills; and
- 40 CFR 63, NESHAP Subpart DDDDD for industrial boilers.

The existing No. 5 Power Boiler, No. 4 Recovery Boiler and No. 4 Lime Kiln are not subject to any new NSPS or NESHAP provisions because the reconstruction costs for each emissions unit are less than 50% of the estimated costs to construct a new unit.

General 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 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". In addition, applicants may choose to conduct a "PSD netting analysis" that includes 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" for only one PSD pollutant, the project may be "significant" for several PSD pollutants. For each significant PSD pollutant, 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 Ambient Air Quality Standards 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 plant a PSD major stationary source of air pollution. Therefore, the project must be reviewed for PSD applicability.

For the project under review, the applicant proposes modifications to the existing No. 4 Recovery Boiler, No. 4 Lime Kiln, and No. 5 Power Boiler. As a separate project, the applicant is also proposing to modify the No. 4 Combination Boiler in addition to a recent PSD permit that modified the existing bark handling system. Due to the nature and close timing of these projects, the Department will review the emissions increases as a single project. The applicant conducted a netting analysis to determine PSD applicability for the affected units considering all emissions increases as well as all emissions decreases for a 5-year period contemporaneous with the project. In this manner, the full emissions increases could be accounted for in the ambient air quality analysis and individual projects will not inadvertently escape BACT determinations. The following table summarizes the applicant's PSD netting analysis for this project.

Pollutant	Emissions in Tons per Year					Subject to PSD?
	Baseline Emissions [1]	Future Potential Emissions [1]	Contemporaneous Emission Changes [4]	Net Emissions Change	PSD Significant Emission Rates	
CO	2094.7	3548.3	19.6	1473.2	100	Yes
NO_X	1504.5	1913.1	- 3.4	405.2	40	Yes
PM	530.0	641.7	- 6.7	105.0	25	Yes
PM_{10}	433.5	521.3	- 4.3	83.5	15	Yes

Pollutant	Emissions in Tons per Year					Subject to PSD?
	Baseline Emissions [1]	Future Potential Emissions [1]	Contemporaneous Emission Changes [4]	Net Emissions Change	PSD Significant Emission Rates	
SAM	183.5	54.5	0.3	- 128.7	7	No
SO_2	4179.2	1064.6	- 362.0	- 3476.6	40	No
TRS	26.0	83.7	- 53.5	4.2	10	No
VOC	329.2	805.2	- 58.1	417.9	40	Yes
Lead	0.260	0.380	- 0.005	0.115	0.6	No
Mercury	0.006	0.008	~ 0	0.002	0.1	No
Fluorides	0.449	0.095	- 0.027	- 0.381	3	No

The PSD netting analysis includes the following emissions units directly affected by this project: No. 4 Power Boiler, No. 5 Power Boiler, No. 4 Lime Kiln, and No. 4 Recovery Boiler. Modification of the No. 4 Combination Boiler was included as a related project, which is under review in Project No. 1070005-045-AC. Subject to the conditions of Permit No. PSD-FL-341, modification of the bark handling system was included as part of this project. The PSD netting analysis also included the previous air construction permit projects from the contemporaneous period: MACT I Compliance, new package boiler, and brown stock washer and delignification system. Emissions from previous pollution control projects which were accounted for in a modeling analysis were not included in the netting analysis. See application for detailed emissions estimates for each unit and project.

Based on the applicant's netting analysis, the projects are subject to PSD preconstruction review for emissions of CO, NO_X, PM/PM_{10}, and VOC. The applicant is required to conduct an air quality analysis to determine ambient impacts and propose BACT controls for the emissions units affected by this project: No. 5 Power Boiler, No. 4 Lime Kiln and No. 4 Recovery Boiler. The No. 4 Power Boiler will be shut down as part of this current project. Previously, Permit No. 1070005-028-AC determined BACT for PM/PM_{10} and VOC emissions from the modified bark handling system. Pending Project No. 1070005-045-AC will determine BACT for CO, NO_X, PM/PM_{10}, and VOC from the No. 4 Combination Boiler.

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. The proposed project requires the Department to make BACT determinations for CO, NO_X, PM/PM_{10}, and VOC emissions from the No. 4 Recovery Boiler and the No. 4 Lime Kiln. Once the No. 5 Power Boiler is converted to natural gas, CO and VOC emissions will potentially increase, but SO_2 and NO_X emissions will decrease. Therefore, the Department will only make BACT determinations for CO and VOC emissions from the No. 5 Power Boiler.

Throughout the BACT analysis, the Department will use PM emissions as a surrogate to also reduce $PM_{2.5}$ and PM_{10} emissions. For this project, conversion of the No. 5 Power Boiler to natural gas will directly reduce all forms of PM emissions as well as SAM and SO_2 emissions, which directly affect visibility.

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 Ambient Air Quality Standards 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, NO_2 and PM/PM_{10}; a PSD increment analysis for NO_2; an Ambient Air Quality Standards (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. 5 POWER BOILER (EU-015)

Discussion of Emissions Changes

Currently, the No. 5 Power Boiler fires residual oil with a maximum sulfur content of 2.35% by weight. This boiler is the largest source of SO_2 emissions at the plant and is considered an eligible unit subject to Rule 62-296.340 (BART), F.A.C. The Department is reviewing a request for an exemption from the BART program based on a visibility modeling analysis. In conjunction with this PSD project and the BART program, the No. 5 Power Boiler will be completely converted to fire natural gas as the sole fuel. The conversion allows this project to avoid PSD preconstruction review for SO_2 and SAM emissions and also satisfy the program requirements under BART. The project is subject to PSD preconstruction review for CO, NO_X, PM/PM_{10}, and VOC emissions. For these pollutants, the following table shows the applicant's estimate of potential emissions changes for these pollutants due to conversion to natural gas.

Pollutant	Emissions, Tons per Year		
	Baseline	Future Potential	Change
CO	48.9	460.8	+ 411.9
NO_X	459.6	311.5	- 148.1
PM	193.6	18.9	- 174.7
PM_{10}	166.5	18.9	- 147.6
VOC	2.7	13.7	+ 11.0

CO and NO_X emissions are based on the natural gas burner bid specifications. PM, PM_{10}, and VOC emissions are based on the emissions factors in Table 1.4-2 of AP-42 for natural gas combustion. Since only CO and VOC emissions are predicted to increase for the No. 5 Power Boiler as a result of the conversion to natural gas, a BACT review is required only for these pollutants. The applicant notes that actual emissions may decrease for all pollutants as a result of the project.

CO and VOC Emissions – No. 5 Power Boiler

Applicant's Proposal

Thermal and catalytic oxidation systems are technically feasible add-on controls. Both technologies would require the firing of additional natural gas to maintain proper destruction temperatures. The applicant conducted a cost analysis for a catalytic oxidation system that concluded annual costs would be more than $8000 per ton of CO removed. The applicant believes these costs are excessive. The applicant proposes a CO BACT limit of 0.185 lb/MMBtu of heat input based on the burner specifications and the efficient combustion of natural gas. Using the emissions factor in Table 1.4-2 of AP-42 for firing natural gas in an industrial boiler, VOC emissions are expected to be less than 0.005 lb/MMBtu and 14 tons per year. Because of the very low VOC emissions expected, the applicant proposes the CO BACT standard as a surrogate BACT standard for VOC emissions.

Department's Review

The burner specification of 0.185 lb CO per MMBtu of heat input at a flue gas oxygen content of 7% oxygen is equivalent to approximately 200 ppmvd. For comparison, the NESHAP Subpart DDDDD requirements for new industrial boilers establishes a CO standard of 400 ppmvd @ 7% oxygen as a surrogate for ensuring complete combustion resulting in low emissions of organic HAP. Natural gas consists of organic compounds, which the boiler will efficiently combust.

Available options for the control of CO and VOC emissions include thermal and catalytic oxidation equipment. However, at the expected low emissions rates for these pollutants, these add-on controls would be cost prohibitive. The Department accepts the applicant's proposal and makes the following draft BACT determinations based on the efficient combustion of natural gas:

> As determined by EPA Method 10, CO emissions shall not exceed 0.185 lb/MMBtu of heat input and 105.2 lb/hour based on the average of three test runs.

Compliance shall be determined by initial an annual stack tests for CO emissions. The CO standard also serves as a surrogate standard representing low VOC emissions from the efficient combustion of natural gas.

4. BACT ANALYSIS FOR THE NO. 4 LIME KILN (EU-017)

The No. 4 Lime Kiln recalcines the spent lime cake (calcium carbonate) to produce the quicklime (calcium oxide), which is used to convert the green liquor to cooking liquor. The maximum processing rate of the No. 4 Lime Kiln is 41.5 tons per hour of calcium carbonate (including inert materials) based on a 24-hour average. The maximum production rate is 19.4 tons per hour of lime. At permitted capacity, the maximum flow rate is 54,200 dscfm @ 10% oxygen. The lime kiln normally operates with flue gas oxygen contents in the 4 to 6 percent range (by volume). The lime kiln fires residual fuel oil containing 2.35% sulfur by weight as the primary fuel. The maximum heat input rate is 140 MMBtu per hour when firing a maximum of 933 gallons per hour of residual oil with a heating value of 150,000 Btu per gallon. There is no restriction on the hours of operation. Particulate matter emissions are controlled by a cyclonic dust collector followed by a wet venturi scrubber. The following table summarizes the applicant's estimated potential emissions changes for the No. 4 Lime Kiln due to the project.

Pollutant	Emissions, Tons per Year		
	Baseline	Future Potential	Change
CO	6.8	71.5	+ 64.7
NO_X	101.4	297.4	+ 196.0
PM	51.3	130.2	+ 78.9
PM_{10}	50.4	128.0	+ 77.6
VOC	2.5	41.4	+ 38.9

The applicant notes that it is likely that there will be no increase in actual emissions from the project. As shown in the above table, the project will increase emissions of CO, NO_X, PM, and VOC; therefore, BACT determinations are required for these pollutants.

Discussion of Exhaust Flow Rate

The Department's ARMS database identifies the exhaust flow rate through the lime kiln as 44,800 acfm, which is equivalent to 24,299 dscfm @ 4% oxygen and 37,400 dscfm @ 10% oxygen. The PSD application identifies the exhaust flow rate through the lime kiln as 58,900 acfm, which is equivalent to 54,200 dscfm @ 10% oxygen. Subsequent tests in 1993 indicated the maximum flow rate was 44,500 dscfm @ 10% oxygen, which was presented in a 1995 PSD application. More recent tests identify the maximum flow rate as 54,200 dscfm @ 10% oxygen. The applicant requests that the maximum flow rate be updated to 58,900 acfm and 54,200 dscfm @ 10% oxygen. In addition, the applicant requests that the mass emissions rates be based on the updated flow rate.

PM Emissions - No. 4 Lime Kiln

The lime dust is made up of particles of sizes ranging from 1 to 100 microns in diameter, while the soda fume consist of very small particles, most less than 1 micron in diameter. Therefore, the lime dust is easily removed from the exhaust gas, but the soda fume proves more difficult. For the existing lime kiln, lime dust is captured by cyclones and recycled back into the process. Exhaust gas from the cyclone is further controlled by a wet venturi scrubber. The most stringent current PM standard for the lime kiln is the NESHAP Subpart MM standard of 0.064 grains per dscf @ 10% O_2, which is equivalent to 29.7 lb/hour.

Applicant's Proposal

Common control equipment for removing PM includes baghouses, electrostatic precipitators, wet scrubbers, and cyclonic separators. Baghouses typically consist of a series of hanging, fine mesh bags and can be designed for removal efficiencies greater than 99%. Electrostatic precipitators charge particles for collection on large hanging plates with removal efficiencies greater than 99%. High-energy wet scrubbers are effective in removing particulate matter with control efficiencies of 95% to 99%. Cyclonic separators use centrifugal forces and low pressure caused by the spinning motion to remove particles with efficiencies ranging from 25% to 95% depending on material density, size and shape. Based on the RACT/BACT/LAER Clearinghouse (RBLC) entries from 1990 to present, all of these control technologies have been applied to lime kilns.

The lime kiln exhaust has a moisture content of approximately 35% and an exit temperature of approximately 600° F (range of 550 to 700° F). Condensation of moisture in a baghouse controlling lime dust would cause blinding, plugging, high pressures, and premature bag failures. For this reason, the applicant believes that a baghouse is better suited for "dry" gas streams and rejects a baghouse for application on the lime kiln.

The existing No. 4 Lime Kiln is currently equipped with a cyclonic dust collector followed by a wet venturi scrubber using fresh water as the scrubbing media. Potentially, an electrostatic precipitator or baghouse could be added to further reduce PM emissions. The applicant identified the following mills that employ the combination of electrostatic precipitator/venturi scrubber on a lime kiln: Koch Cellulose Mill in Leaf River, Mississippi; Koch Cellulose Mill in Brunswick, Georgia; Georgia-Pacific Mill in Port Hudson, Louisiana; and Georgia-Pacific Mill in Naheola, Alabama. Due to the applicant's concerns regarding feasibility of a baghouse, the applicant provided only a cost analysis for adding an electrostatic precipitator to the existing system.

The applicant estimates the annualized cost to operate and maintain an electrostatic precipitator (including capital recovery) at $1,403,393. After control by the existing combination of cyclones/venturi scrubber, baseline PM emissions were estimated as 58 tons per year. Assuming 99% control efficiency for the electrostatic precipitator, the additional PM emissions removed would be 57 tons per year. Based on these estimates, the cost effectiveness to add an electrostatic precipitator is more than $24,000 per ton of PM removed. The applicant believes these costs are excessive.

The applicant also conducted an incremental cost effectiveness calculation to compare the existing cyclones/venturi scrubber system to the cyclones/venturi scrubber/ electrostatic precipitator system. The applicant estimates the annualized costs for the venturi scrubber as $463,435. Total annualized costs for the cyclones/venturi scrubber/electrostatic precipitator system would be $1,866,828. The applicant asserts that the control efficiency for the cyclones/venturi scrubber/electrostatic precipitator system would be 99.9%*, which would emit approximately 6 tons of PM per year. Therefore, the applicant estimates the incremental cost as:

Incremental Costs = ($1,866,828 - $463,435) / (58 tons PM/year – 6 tons PM/year) > $26,000 per ton PM removed

The applicant believes the incremental cost difference between the two control options is excessive. The applicant comments that the existing mills with electrostatic precipitator/venturi scrubbers in place installed the electrostatic precipitators to regain compliance with the emissions standards. Cost effectiveness estimations were not required under these scenarios. In addition to the cost analysis, the applicant considered the following:

- Lime kilns are subject to a PM standard of 0.13 grains per dscf @ 10% O_2 when firing liquid fossil fuel as specified in NSPS Subpart BB.
- The No. 4 Lime Kiln is subject to an existing BACT standard for PM of 0.081 grains per dscf @ 10% O_2 as specified in Permit No. PSD-FL-171 (AC54-192551) issued on June 12, 1991.
- Lime kilns are subject to a PM standard of 0.064 grains per dscf @ 10% O_2 as specified in NESHAP Subpart MM.

- For lime kilns, the RBLC identifies previous BACT determinations for PM emissions in the range of 0.01 to 0.033 grains per dscf @ 10% O_2.

Although many of the RBLC BACT standards are based on control by an electrostatic precipitator, the applicant maintains that a high-energy wet venturi scrubber is an effective PM control technology. Therefore, based on the existing cyclones/venturi scrubber system, the applicant proposes to retain the current PM standard of 0.064 grains per dscf @ 10% O_2 and 29.73 lb/hour as BACT for the lime kiln, which is equivalent to the PM standard in NESHAP Subpart MM for lime kilns.

For visible emissions, the applicant indicated that the current standard is "less than 20% opacity". Although this is the Department's general visible emissions standard specified in Rule 62-296.320(4)(b)1, F.A.C., Permit No. PSD-FL-171 (AC54-192551) did not require adherence due to moisture interference. For a visible emissions observation of 20% opacity or more, the Department could require the permittee to conduct a special PM mass emissions tests. The applicant requests that this same protocol for visible emissions remain as previously established.

Department's Review

The Department does not endorse the applicant's cost analysis or equipment cost estimates. Although consideration is given to existing controls, the evaluation of new equipment should be based on the potential reductions from the lowest enforceable emissions rate and the control capabilities of the new system. The cost analysis should be based on the following assumptions: applicant's estimated annualized cost for an electrostatic precipitator of $1,403,393; a new controlled PM emissions rate of 4.65 lb/hour (99.8% reduction and 0.01 grains per dscf); and the current lowest controlled emissions rate of 0.064 grains per dscf @ 10% O_2 specified by NESHAP Subpart MM (29.7 lb/hour). This results in a cost effectiveness estimate of more than $12,000 per ton of PM removed by the proposed electrostatic precipitator. The revised cost effectiveness is about half of the applicant's estimate, but remains very high due to the existing controls. Although a detailed cost analysis was not conducted, the cost effectiveness for a baghouse would also be cost prohibitive due to the relatively low controlled emissions rate for the existing cyclones/venturi scrubber.

Based on a review of EPA's RBLC, a summary of PM BACT determinations since 1990 for similar lime kiln throughputs is shown below. The maximum lime production rate for the No. 4 Lime Kiln is 467 tons per day (TPD).

Facility/Location/Permit Issued	Status/Capacity	Control System	PM Limit	Basis
Weyerhaeuser - Flint River, GA May 2003	New 370 TPD	Electrostatic Precipitator	0.01 gr/dscf @ 10% O_2	Subpart MM (new unit)
Port Hudson, LA January 2002	Unit 1 Existing 340 TPD	Wet Scrubbers	25.76 lbs/hr	BACT
Port Hudson, LA January 2002	Unit 2 Existing 270 TPD	Wet Scrubbers	20.45 lbs/hr	BACT
Weyerhaeuser Company, MS September 1996	Existing 504 TPD	Electrostatic Precipitator	0.033 gr/dscf @ 10% O_2	BACT
Buckeye Florida, FL August 1996	Existing 750 TPD	Electrostatic Precipitator	20 lbs/hr	BACT
Williamette - Marlboro Mill, SC April 1996	New 450 TPD	Electrostatic Precipitator	0.033 gr/dscf @ 10% O_2	BACT
International Paper - FL (formerly Champion International) March 1994	Existing 500 TPD	Electrostatic Precipitator/ Venturi Scrubber/ Packed Column Mist Separator	10.90 lbs/hr	BACT
Gulf States Paper – AL January 1994	New 650 TPD	Electrostatic Precipitator	22 lbs/hr @ 10% O_2 (gas) 42 lbs/hr @ 10% O_2 (oil)	BACT

For comparison purposes, capacity of the No. 4 Lime Kiln is 996 TPD. Note that BACT standards have been set in terms of grains per dscf, lb/hour, or both. In general, the term "grains per dscf" is used for units controlled by an electrostatic precipitator. Correcting PM standards for the oxygen content is generally used for pure combustion sources.

Performance Test Date	Tested PM Emissions			
	grains/dscf @ 10% O_2	lb/hr	Process Rate, TPH	lb/ton processed
07/25/2006	---	14.50	38.6	0.38
09/08/2005	---	17.60	*37.4*	*0.47*
08/26/2004	0.027	11.50	*37.4*	*0.31*
02/26/2004	0.01	4.20	39.3	0.11
01/14/2003	0.033	11.94	*37.4*	*0.32*
07/03/2002	0.028	9.51	*37.4*	*0.25*
07/13/2001	0.029	10.77	*37.4*	*0.39*
04/12/2000	0.044	16.03	*37.4*	*0.43*
05/17/1999	0.03	7.20	34.4	0.21
05/12/1998	---	13.00	37.5	0.35
02/13/1997	---	17.48	36.0	0.49
03/30/1996	---	12.30	37.0	0.33
04/27/1995	---	18.30	*37.4*	*0.49*

PM emissions from the lime kiln should primarily be a function of the process rate of the material introduced to the kiln. The uncontrolled PM emissions rate in Table 10.2-1 of AP-42 for a lime kiln is provided as 56 lb/ton of air-dried unbleached pulp. Based on a plant capacity of 77 tons per hour of air-dried unbleached pulp, the estimated uncontrolled PM emissions rate is approximately 4312 lb/hour. The PM emission factor in Table 1.3-1 of AP-42 for residual oil combustion is 24.8 lb/1000 gallons of oil fired with a maximum sulfur content of 2.35% by weight. For the No. 4 Lime Kiln, this equates to approximately 23 lb/hour, which represents less than 1% of the predicted total uncontrolled PM emissions. So, the majority of PM emissions are lime dust from the process.

Based on data from the Department's ARMS database, the table summarizes the actual tested PM emissions rates from the existing cyclone/wet venturi scrubbing system installed on the No. 4 Lime Kiln. Annual tests are conducted at 90% to 100% of the maximum processing rate. Hourly mass emissions rates have been as high as 18.3 lb/hour, as low as 4.2 lb/hour, and averaged 12.6 lb/hour. For tests that identified the process rate, the table also shows a corresponding emissions rate in terms of "lb/ton of lime cake processed". The maximum processing rate of the kiln is 41.5 tons/hour of lime cake. For tests without a known process rate, the processing rate was assumed at 90% of the maximum (*37.4 TPH*) since tests are generally conducted at rates greater than 90%.

The Department intends to establish the draft BACT standards based on the rate of lime cake fed to the kiln. Assuming a margin of 25% above the maximum hourly emissions rate of 18.3 lb/hour, the corresponding emissions rates would be 22.9 lb/hour and 0.55 lb/ton of lime cake processed, which represents a 99% reduction from the estimated uncontrolled emissions. All of the tested emissions rates were less than 0.55 lb/ton of lime cake. At a maximum flow rate of 54,200 dscfm @ 10% oxygen, the equivalent PM emissions rate would be:

PM = (22.9 lb/hour) (7000 grains/lb) (hour/60 minutes) (minute/54,200 dscf @ 10% O_2) = 0.049 grains per dscf @ 10% O_2

This is approximately 75% of the current lowest emissions applicable standard of 0.064 grains per dscf @ 10% O_2 specified by NESHAP Subpart MM. Therefore, the Department establishes the following draft BACT standards based on the demonstrated capabilities of the existing control configuration, the actual tested emissions rates, and the maximum process rate of the lime kiln.

As determined by EPA Method 5 tests, PM emissions from the No. 4 Lime Kiln shall not exceed 0.55 lb per ton of actual material processed and 22.9 lb/hour based on the average of three test runs.

The draft standard is similar to the terms for PM standards established for Portland cement kilns, which are based on material feed rates to the preheater. The draft standard represents a control efficiency of greater than 99% for the existing cyclone/venturi scrubber system. Initial and annual stack tests shall be conducted at permitted capacity to demonstrate compliance with these standards. Permitted capacity is between 90% and 100% for the maximum processing rate of 41.5 tons/hour.

Moisture in the exhaust plume due to the wet scrubber interferes with an accurate determination of opacity. In lieu of an opacity standard, the draft permit requires the permittee to conduct the same continuous parametric monitoring that is required for the PM standard specified in NESHAP Subpart MM for existing lime kilns. Acceptable parametric ranges must be established for the scrubber pressure drop and liquid flow rate based on stack tests demonstrating compliance *with the PM BACT standards*. Parameters must be continuously monitored and recorded at least every 15 minutes and a three-hour block average determined.

NO_x Emissions - No. 4 Lime Kiln

Discussion of NO_X Emissions and Available Control Technologies

In general, NO_X emissions from the lime kiln are a combination of thermal NO_X and fuel NO_X. Thermal NO_X is produced from a series of chemical reactions in which diatomic nitrogen and oxygen present in the combustion air dissociate in a high temperature combustion zone and react to form NO_X. Fuel NO_X is generated from nitrogen available in the fuel oil that is oxidized to NO_X. The spent lime cake and residual fuel oil are low in nitrogen content, so the primary NO_X mechanism for lime kilns is thermal NO_X.

Based on the BACT determinations listed in the RBLC since 1990, the following NO_X control technologies were identified for lime kilns: no controls, low-NO_X burners, efficient operations, good combustion control, and preventive maintenance. It is also possible that the following add-on NO_X control technologies could be applied to a lime kiln.

- *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. This system converts NO_X to elemental nitrogen, carbon dioxide, and water vapor. The temperature range for a conventional SCR catalyst is 550° to 750° F; however, new catalyst formations are available for temperatures of 1000° F. SCR systems can achieve NO_X reductions approaching 90%.
- *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 achieve NO_X reductions of 50% on some applications.
- *Low-NO_x Burners (LNBs)*: LNBs provide a stable flame that has 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. NO_X reductions vary from 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. NO_X reductions vary from 0 to 30%.

Applicant's Proposal

SCR technology has not been applied to lime kilns due to the variable exhaust temperatures associated with the process. Further, the applicant believes that the optimum temperature range for the catalytic reaction is 575 to 750° F. A lime kiln typically operates in the range of 1600° F - 2700° F. Injected ammonia may also react with sulfur to form ammonium bisulfate, which has the potential to create a visible and/or detached plume. The lime may also react with the sulfur to form calcium sulfate. Ammonium bisulfate and calcium sulfate coatings, along with other dusts, may block the catalyst pores, which can reduce catalyst effectiveness and lead to premature failure. The SCR unit could be placed downstream of the wet scrubber to alleviate the catalyst blockage problem; however, the flue gas is approximately 170° F and would require a heat exchanger (i.e., an additional gas-fired duct burner) system to achieve the desired reaction temperature of greater than 575° F. SCR technology is not listed for lime kilns in the RBLC. The applicant does not believe SCR technology is feasible for lime kilns because it has not been demonstrated and due to concerns over premature catalyst failure.

Several difficulties preclude use of an SNCR system for control of NO_X emissions from a lime kiln. The correct temperature window of 1600° F to 2100° F occurs inside the rotating body of the kiln. Locating injection nozzles in such an area is not technically feasible at the present time and has not been attempted on any lime kiln. If kiln temperatures exceed 2,100° F, ammonia injected with the SNCR system will oxidize and form additional NO_X. Due to load fluctuations, it will be difficult to maintain the correct ammonia-to-NO_X molar ratio, which leads to the over injection of ammonia. Excess ammonia, known as ammonia slip, would be released directly to the atmosphere. Ammonia slip may also lead to the formation of ammonium salts, which can form a visible plume from the stack. Further, the formation of ammonia salts in the kiln could cause process downtime due to "ringing" effects on the kiln interior causing the buildup of materials. SNCR technology is not listed for lime kilns in the RBLC. The applicant does not believe SNCR technology is feasible for lime kilns because it has not been demonstrated and due to the technical issues discussed.

Although LNBs have been extensively tested and used in utility boilers and industrial furnaces, the transfer of this technology to lime processing has been met with difficulties. Burner flame properties are critical to the quality control and calcining process to convert a high percentage of mud to re-burned lime in the lime kiln. The burner flame shape and properties have a dramatic effect on the calcining efficiency. Poor efficiency increases energy usage and decreases the calcining capacity of the kiln. Due to these technical complexities, the conversion of a standard lime kiln burner to low NO_X design is not yet technically feasible. Further, in a BACT determination for the Weyerhaeuser Mill, Georgia stated that there are no commercially available LNBs on the market for a lime kiln application. The applicant does not believe that LNBs are feasible or available for lime kilns.

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. NO_X reductions vary from 0 to 30%. The current kiln system minimizes oxygen levels to approximately 4% to 6%.

NO_X formation can be minimized by proper kiln design and operation. Generally, emissions are minimized by properly controlling air in the air/fuel injection zones to maintain kiln temperatures at the lower end of the desired range. Ideally, maintaining a low-oxygen condition near fuel injection points approaches an off-stoichiometric, staged combustion process. For the No. 4 Lime Kiln, the flue gas oxygen content is low at 4% to 6% by volume when compared to the reference oxygen content of 10% by volume specified for other emissions standards in NESHAP Subpart MM. Good combustion practices and low excess air is technically feasible and currently in use for this unit.

Based on EPA's RBLC, NO_X BACT determinations for lime kilns since 1990 are in the range of 100 to 340 ppmvd @ 10% O_2 and are based on: no controls, LNBs, efficient operations, good combustion control, and preventive maintenance. There is only one entry listing LNBs for two small existing lime kilns (8.4 tons/hour of lime produced) firing recycled fuel oil with a NO_X standard of 3.5 lb/ton of lime produced. However, the current NO_X standard for the No. 4 Lime Kiln is 290 ppmvd @ 10% O_2 and 50.3 lb/hour, which is approximately 2.6 lb/ton of lime produced.

The current NO_X standard is at the high end of previous BACT determinations in EPA's RBLC. Based on tests, actual NO_X emissions were 33.7 lb/hour in 2004 and 17.9 lb/hour in 2005. Therefore, the applicant proposes reducing the NO_X standard from 290 to 175 ppmvd @ 10% O_2 with an equivalent mass emissions rate of 67.9 lb/hour at the increased flue gas flow rate.

Department's Review

Performance Test Date	Tested NO_X Emissions
	lb/hr
3/30/96	40.0
2/13/97	27.7
5/13/98	23.0
5/17/99	41.0
4/12/00	34.2
7/13/01	32.3
7/3/02	18.9
1/14/03	32.0
2/26/04	33.7
9/8/05	17.9
7/25/06	16.8

The table summarizes the results of annual tests conducted at 90% to 100% of the maximum capacity. As shown, the hourly mass emissions rates have been as high as 41.0 lb/hour, as low as 16.8 lb/hour, and averaged 28.9 lb/hour. Assuming permitted capacity, the range of NO_X emissions is approximately 43 to 106 ppmvd @ 10% O_2, which is relatively low for a calcining kiln. The Department is not aware of any lime kilns with SCR or SNCR systems installed; however, these systems are considered technically feasible given adequate temperature requirements. Neither is the Department aware of any low-NO_X kiln burners that will deliver significantly lower NO_X emissions levels.

Based on actual emissions from the No. 4 Lime Kiln and the nature of this project, it is likely that such add-on controls would be cost prohibitive. The Department also considers that the nature of the \$2 million project is not to increase kiln production, but for major repair of the hot-end shell section and replacement of existing coolers. Therefore, the Department establishes the following draft BACT standards based on good combustion design and practices for the No. 4 Lime Kiln.

> As determined by EPA Method 7E, NO_X emissions shall not exceed 140.0 ppmvd @ 10% O_2 and 54.2 lb/hour based on the average of three test runs.

The standard is based on the demonstrated NO_X levels for the No. 4 Lime Kiln as well as the established BACT standards for similar units. Compliance with the NO_X standards shall be demonstrated by conducting initial and annual stack tests at permitted capacity.

CO and VOC Emissions - No. 4 Lime Kiln

Discussion of CO and VOC Emissions and Available Control Technologies

CO and VOC emissions are formed due to incomplete combustion of the fuels. The main options for reducing CO and

VOC emissions are thermal oxidation, catalytic oxidation and combustion modifications. Thermal oxidizers would rarely be used to control kiln exhausts because it would require high fuel firing rates to achieve the necessary oxidizing temperatures. In general, thermal oxidizers are used when there are high concentrations of organic compounds. For relatively dust-free exhausts such as gas turbines, oxidation catalysts may be used to reduce CO and VOC emissions. Oxidation catalysts typically operate at temperatures between approximately 600° F and 1100° F. Depending on the specific pollutants, inlet concentrations and other factors, reductions of more than 90% are possible.

Applicant's Proposal

The applicant believes that thermal incineration is cost prohibitive due to the additional fuel requirements to achieve and maintain the necessary destruction temperature. The applicant does not believe the use of catalytic oxidation is appropriate due to the potential for premature failure of the catalyst from poisoning (metals in residual oil) and plugging/fouling (high dust loading). Therefore, post-combustion controls do not seem feasible.

Minimizing the formation of CO emissions from lime kilns is generally achieved by ensuring efficient combustion. Uniform and efficient combustion is a function of the three "T's": turbulence (thorough mixing of air and fuel), temperature (high enough to complete oxidation), and time (sufficient residence time at given combustion temperature). Due to the long residence time and high temperatures in the lime kiln, CO emissions are low and have been verified by stack testing.

Based on EPA's RBLC database for CO BACT determinations from lime kilns since 1990, the following control technologies were identified: good combustion practices, kiln design, proper combustion techniques, and no controls. The RBLC data shows previous CO BACT determinations ranging from 45 to 1400 ppmvd @ 10% O_2. For the No. 4 Lime Kiln, the current CO standard is 69 ppmvd @ 10% O_2, which is at the low end for previous CO BACT determinations. Therefore, the applicant proposes to retain the current standard of 69 ppmvd @ 10% O_2 with an equivalent mass emissions rate of 16.3 lb/hour at the increased flow rate.

Based on EPA's RBLC database for VOC BACT determinations from lime kilns since 1990, the following control technologies were identified: good combustion practices, kiln design, proper combustion techniques, venturi scrubber using fresh water, and no controls. The RBLC data shows previous BACT determinations ranging from 25 to 185 ppmvd @ 10% O_2 for VOC emissions. For the No. 4 Lime Kiln, the current VOC standard is 185 ppmvd @ 10% O_2, which is at the high end for previous VOC BACT determinations. Therefore, the applicant proposes to reduce the VOC standard to 70 ppmvd @ 10% O_2 with an equivalent mass emissions rate of 9.4 lb/hour (determined as methane).

Department's Review

Test Date	CO, lb/hour	VOC, lb/hour
3/30/96	1.1	0.3
2/13/97	1.1	1.3
5/13/98	5.3	2.8
5/17/99	1.4	0.3
4/12/00	3.3	1.1
7/13/01	2.1	0.9
7/3/02	5.6	0.6
1/14/03	1.8	0.6
2/26/04	1.4	0.6
9/8/05	2.0	0.6
7/25/06	7.0	0.1

Based on the Department's ARMS database, CO emissions range from 1.1 to 7.0 lb/hour during the annual stack tests conducted at permitted capacity. Similarly, VOC emissions ranged from 0.1 to 2.8 lb/hour. The low emissions levels are expected due to the kiln temperatures and long residence times. Thermal and catalytic oxidation is technically feasible, but impractical for this application and would result in prohibitive costs due to currently low CO and VOC emissions. Therefore, the Department establishes the following draft BACT standards based on good combustion design and practices.

- As determined by EPA Method 10, CO emissions from the lime kiln shall not exceed 69.0 ppmvd @ 10% O_2 and 16.3 lb/hour based on the average of three test runs.
- As determined by EPA Method 25A, VOC emissions from the lime kiln shall not exceed 70.0 ppmvd @ 10% O_2 and 9.4 lb/hour (THC determined as methane) based on the average of three test runs.

The standards are based on the demonstrated CO and VOC levels for the No. 4 Lime Kiln as well as the established BACT standards for similar units. Compliance with the CO and VOC standards shall be demonstrated by conducting initial and annual stack tests at permitted capacity. If consecutive annual tests show compliance at 50% of the standard or less, the test frequency will be reduced to testing prior to renewal of the operation permit.

5. BACT ANALYSIS - NO. 4 RECOVERY BOILER (EU-018)

The No. 4 Recovery Boiler (EU-018) fires black liquor solids (BLS) as the primary fuel at a maximum permitted firing rate of 210,000 lb/hour of BLS. Based on an as-fired heating value of 6410 Btu per lb of BLS, the maximum heat input rate is 1346 MMBtu per hour. Residual fuel oil containing a maximum sulfur content of 2.35% by weight is fired as a startup and supplemental fuel. The firing of residual oil is restricted to no more than 7,860,640 gallons per consecutive 12 months, which is less than 10% of the maximum annual heat input. At permitted maximum capacity, the exhaust flow rate is 294,000 dscfm @ 8% O_2. There is no restriction on the hours of operation. The recovery boiler will remain subject to all existing emissions standards. The project is subject to PSD preconstruction review for emissions of CO, NO_X, PM, and VOC. The following table summarizes the applicant's estimated of potential emissions changes for the No. 4 Recovery Boiler due to the project.

Pollutant	Emissions, Tons per Year		
	Baseline	Future Potential	Change
CO	1249.3	2245.6	+ 996.3
NO_X	473.2	738.1	+ 264.9
PM	134.7	331.1	+ 196.4
PM_{10}	101.0	248.3	+ 147.3
VOC	9.5	92.0	+ 82.5

The applicant notes that actual emissions may not increase as a result of the project. As shown in the above table, the project will increase emissions of CO, NO_X, PM, and VOC; therefore, BACT determinations are required for these pollutants.

PM Emissions – No. 4 Recovery Boiler

PM emissions from the recovery boiler are currently controlled by an electrostatic precipitator. Removal of the entrained ash is crucial to overall material recovery as it is reused in the process.

Applicant's Proposal

Common control equipment for removing PM includes baghouses, electrostatic precipitators, and wet scrubbers. Baghouses typically consist of a series of hanging, fine mesh bags and can be designed for removal efficiencies greater than 99%. Electrostatic precipitators charge particles for collection on large hanging plates with removal efficiencies greater than 99%. High-energy wet scrubbers are effective in removing particulate matter with control efficiencies approaching 98%. As reflected in EPA's RBLC, nearly all recovery boilers at pulp and paper mills in the United States use electrostatic precipitators to control particulate matter emissions.

The applicant selects an electrostatic precipitator as the top control option. Since an electrostatic precipitator already controls PM emissions from the No. 4 Recovery Boiler, no additional controls are proposed. Based on the existing design, the applicant proposes a BACT standard of 0.030 grains per dscf @ 8% O_2. This is the current standard for the recovery boiler as established in Permit No. PSD-FL-226 issued on September 21, 1995. A review of EPA's RBLC identifies BACT limits ranging from 0.021 to 0.15 grains per dscf for recovery boilers. Therefore, the proposed standard is at the low end of the range for previous BACT determinations. For comparison purposes, EPA promulgated the following standards for recovery boilers:

- NSPS Subpart BB: PM $\leq$ 0.044 grains per dscf @ 8% O_2; and
- NESHAP Subpart MM: PM $\leq$ 0.044 grains per dscf @ 8% O_2 as a surrogate for reducing metal HAP emissions.

Also, the applicant requests retaining the current visible emissions standard of 20% opacity (normal operation) except for up to 6% of the opacity readings collected during a calendar quarter no greater than 35%, which is standard under 40 CFR 63, NESHAP Subpart MM. Compliance will be verified by the existing continuous opacity monitoring system (COMS).

Department's Review

Compliance tests conducted on the existing recovery boiler over the last 10 tears show PM emissions ranging from 0.004 to 0.030 grains per dscf @ 8% O_2. The applicant's proposed standard of 0.030 grains per dscf @ 8% O_2 is equivalent to

0.0036 lb PM per ton of air-dried unbleached pulp. The uncontrolled PM emission factor from Table 10.2-1 in AP-42 is 180 lb per ton of per ton of air-dried unbleached pulp. So, the estimated control efficiency of the existing electrostatic precipitator is greater than 99%. The Department agrees that an electrostatic precipitator is a top control system for the recovery boiler process. Therefore, the Department establishes the following draft BACT PM standards based on the existing electrostatic precipitator.

- As determined by EPA Method 5 or 29, PM emissions shall not exceed 0.030 grains per dscf @ 8% O_2 and 75.6 lb/hour based on the average of three test runs.
- Once the ESP is placed in service during startup of the recovery boiler, visible emissions shall not exceed 20% opacity as determined by COMS and EPA Method 9.

Compliance with the PM standard shall be demonstrated by conducting initial and annual stack tests. Compliance with the opacity standard shall be demonstrated by the existing COMS and EPA Method 9. The Department notes that Permit No. PSD-FL-171 (AC54-192550) issued on June 12, 1991 established a BACT standard for visible emissions of no more than 20% opacity for the existing recovery boiler.

NO_X Emissions – No. 4 Recovery Boiler

In general, NO_X emissions from recovery boilers are a combination of thermal NO_X and fuel NO_X. Thermal NO_X is produced from a series of chemical reactions in which diatomic nitrogen and oxygen present in the combustion air dissociate in a high temperature combustion zone and react to form NO_X. Fuel NO_X is generated when nitrogen available in the BLS or fuel oil is oxidized to NO_X. Due to moderate combustion zone temperatures (< 1500° F) and staged combustion techniques, thermal NO_X from a recovery boiler is not believed to be the significant portion of overall NO_X emissions. However, it is possible for higher temperatures in the combustion zone to oxidize more of the available fuel nitrogen to NO_X. In general, NO_X emissions from recovery boilers are relatively low (< 125 ppmvd) due to moderate furnace temperatures and low nitrogen content of BLS (< 0.10% by weight). For comparison, the nitrogen content of residual oil ranges from 0.2 to 0.5% by weight.

<u>Applicant's Proposal</u>

The applicant identified the following available NO_X controls.

- *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. This system converts NO_X to elemental nitrogen and water vapor. The optimum temperature range for a conventional SCR catalyst is 550° to 750° F; however, new catalyst formations are available for temperatures of 1000° F. SCR systems can achieve NO_X reductions approaching 90%.
- *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 achieve NO_X reductions of 50% on some applications.
- *Overfire Air (OFA)*: The recovery boiler currently stages combustion air with a 3-level 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 two more stages to complete combustion of the fuel while maintaining the low temperatures that will prevent thermal NO_X formation. OFA systems can reduce NO_X emissions by 20% to 50%.
- *Low-NO_X Burners (LNBs)*: LNBs provide a stable flame that has 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. NO_X reductions vary from 20% to 50%.
- *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. NO_X reduction potential varies from 15% to 20%.

- *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. NO_X reductions vary from 0 to 30%.

An SCR system is recognized as the top control option for reducing NO_X emissions. However, the applicant expresses concerns regarding the feasibility of installing an SCR system due to premature deactivation of the catalyst. The recovery boiler fires BLS as the primary fuel, which results in high particulate matter loading of boiler exhaust. If the catalyst were installed prior to the electrostatic precipitator, the catalyst would quickly plug and foul due to deposits from particles in the flue gas. For this reason, the applicant does not believe installation of an SCR system prior to the electrostatic precipitator is technically feasible.

If the catalyst were installed after the existing electrostatic precipitator, the exhaust gas would have to be heated from ~425° F to ~700° F to achieve an effective operating temperature. The cost of firing a duct burner with natural gas would significantly add to the cost of operating such an SCR system. In addition, fuel analyses of the BLS indicate the presence of sodium (18.7% by weight), potassium (1.09% by weight), and chlorine (0.56% by weight), which are known catalyst poisons. Again, the applicant expresses concerns regarding the technical feasibility of an SCR system due to premature deactivation of the catalyst from poisoning.

The applicant estimates a total direct capital cost for an SCR system of nearly $16 million and total annualized cost of nearly $7.5 million. The cost effectiveness of an SCR system is estimated at nearly $17,600 per ton of NO_X removed based on actual NO_X emissions (2004 – 2005) of 473.2 tons per year and 90% SCR control efficiency. The applicant rejects SCR due to the technical challenges and excessive costs.

SNCR is the next top control option for reducing NO_X emissions. The applicant believes that an SNCR system is not technically feasible for a recovery boiler, which is a complete chemical reaction process. Any disruption of the delicate balance of chemistry within the boiler could potentially damage it, reduce unit availability, impact the quality of the product, or otherwise unacceptably affect the system. The applicant contacted two SNCR vendors (Fuel-Tech, Inc. and Aker Kvaerner Power, Inc.). These companies indicated that SNCR systems are not yet commercially available for recovery boilers. Both companies are working on studies in Sweden to determine whether or not SNCR can be a viable NO_X control option for recovery boilers. Based on these discussions, the applicant rejects SNCR because it is not commercially available for recovery boilers.

Of the remaining control options, staged combustion with OFA is the next likely control option. The existing recovery boiler currently employs staged combustion with primary, secondary and tertiary OFA. The applicant proposes to add a fourth level (quaternary) of OFA to further stage combustion air and inhibit NO_X formation. A well-designed OFA and control system promotes uniform combustion, which removes hot and cold spots in the combustion zone. OFA systems are routinely employed to reduce NO_X emissions from recovery boilers.

Typical NO_X emissions from recovery boilers range from 75 to 150 ppmv, depending upon the number of levels of combustion air used to control NO_X emissions. A review of EPA's RBLC shows previous BACT determinations for recovery boilers ranging from 70 to 210 ppmv. The BACT control technologies include combustion control, staged combustion, boiler design and operation, and process controls. One entry lists LNBs for the supplemental firing of natural gas. Another entry lists the addition of a fourth level of combustion air with a NO_X emission limit of 100 ppmv.

The current NO_X limit for the No. 4 Recovery Boiler is 80 ppmvd @ 8% O_2 and 168.5 lb/hour. The vendor guarantees NO_X emissions in the range of 78 to 90 ppmvd @ 8% O_2 for the modified OFA system with a fourth level of OFA. This is based on a 75% solids content of the BLS, which is the proposed level once the new crystallizer is added. The current limit is within the vendor guarantee and at the low end of the previous NO_X BACT determinations for recovery boilers. Considering a reduction in CO emissions with the improved OFA system, the applicant proposes to retain the current NO_X limit of 80 ppmvd @ 8% O_2.

Department's Review

The Department does not endorse the applicant's SCR cost estimates, but does recognize the considerable costs of installing and operating such a system. It is noted that the applicant's cost effectiveness estimate of $17,600 per ton of NO_X removed was based on actual NO_X emissions and not potential NO_X emissions. However, the cost effectiveness would still be more than $10,000 per ton of NO_X removed assuming the applicant's estimated annualized cost of $7.5 million, potential NO_X emissions of 738 tons per year (based on 80 ppmvd), and 90% reduction. SCR will not be considered due to the high estimated costs, which are partially due to the relatively low NO_X emissions from this industrial boiler.

The Department found only the following reference to employing SNCR on a recovery boiler in Sweden (Sodra Skogsagma), "... Demonstrations of SNCR, in addition to municipal waste incinerators and wood- and coal-fueled district heating plant boilers, included a pulp and paper mill Kraft recovery boiler, where a 60% reduction from uncontrolled emissions of 60 ppm was attained.[1]" The Department contacted Fuel-Tech, an SNCR vendor, and discussed the technology for recovery boilers. The vendor could not identify any known installations of SNCR on a recovery boiler, but was aware of the performance test in Sweden. That test was conducted over only a few hours and then the equipment removed. The vendor was not aware of any long term performance tests.

Based on the discussions with SNCR vendors, the Department was unable to determine that SNCR is commercially available and demonstrated for recovery boilers at this time. A review of EPA's RBLC shows that previous NO_X BACT determinations have relied upon combustion control techniques. The Department's BACT determination will be based on adding a fourth level of combustion air.

In September of 1995, the Department issued Permit No. PSD-FL-226 (AC54-266676) for this unit with a NO_X BACT standard of 80 ppmvd @ 8% O_2. For reference, this is approximately 0.13 lb/MMBtu of heat input. A review of EPA's RBLC shows BACT standards ranging from 70 to 210 ppmvd @ 8% O_2. For the existing recovery boiler, actual test results for the No. 4 Recovery Boiler show NO_X emissions ranging from 48 to 74 ppmvd @ 8% O_2. The additional solids content of the BLS may result in higher temperatures, but the improved OFA system should compensate by further staging combustion to inhibit additional NO_X formation. The Department's draft NO_X BACT determination is:

> As determined by data collected from the required CEMS, NO_X emissions from the recovery boiler shall not exceed 80.0 ppmvd @ 8% O_2 and 168.5 lb/hour based on a 30-day rolling average, excluding periods of startup and shutdown.

The new CEMS-based standard will allow the continuous demonstration of compliance and ensure the use of good combustion practices. The new standard will replace the previous NO_X standard and is believed to be more stringent due to the continuous compliance demonstration. Although NO_X emissions should be low during startup and shutdown, the standard excludes data collected during these periods because emissions rely on staged combustion, which is not in full effect during these periods.

CO and VOC Emissions – No. 4 Recovery Boiler

CO and VOC emissions are formed due to incomplete combustion of the fuels. The main options for reducing CO and VOC emissions are thermal oxidation, catalytic oxidation and combustion improvements. CO and VOC emissions can be oxidized to carbon dioxide either thermally or catalytically. Thermal oxidizers are capable of control efficiencies of more than 90% at operating temperatures approaching 1800° F. However, thermal oxidizers are not considered for the control of boiler exhausts due to the large fuel requirements necessary to maintain the high oxidizing temperatures. For low-dust exhausts, oxidation catalysts may be used to further the reduction of CO and VOC emissions at lower operating temperatures (600° F to 1100° F). Oxidation catalysts are capable of reductions greater than 90% depending on the specific pollutants and inlet concentrations.

Uniform and efficient combustion is a function of the three "T's": turbulence (thorough mixing of air and fuel), temperature (high enough to complete oxidation), and time (adequate residence time at a sufficient combustion temperature). For the recovery boiler, good combustion includes adequate control of the ratio of BLS to combustion air in the furnace. In addition, staged combustion with overfire air promotes uniform mixing and complete combustion of the fuel. Minimizing the formation of CO/VOC emissions from boilers is generally achieved by ensuring efficient combustion.

<u>Applicant's Proposal</u>

Oxidation catalysts are sensitive to poisoning, blinding, plugging, fouling, and erosion. If installed before the electrostatic precipitator, particulate matter would soon erode, plug and foul the catalyst. If installed after the electrostatic precipitator, residual particles may still be sufficient to build-up and clog catalyst pore spaces and reduce effectiveness. In addition, BLS contain significant amounts of sodium (18.7% by weight), potassium (1.09% by weight), and chlorine (0.56% by weight) as well as lesser amounts of zinc, lead, copper, magnesium, arsenic, and vanadium. These contaminants are recognized catalyst poisons that would prematurely deactivate the catalyst and disrupt operation. A review of EPA's RBLC identifies the following CO and VOC control options: boiler design, good combustion practices, proper combustion techniques and operating practices, combustion control, good combustion control of flame temperature and excess air, boiler design and operation, and efficient operation. These are all descriptions of good combustion design and practices. The applicant

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

rejects an oxidation catalyst as technically infeasible for a recovery boiler due to poisoning from flue gas contaminants.

The existing No. 4 Recovery Boiler is subject to CO standards of 800 ppmvd @ 8% O_2 based on a three-hour average and 400 ppmvd @ 8% O_2 based on a 24-hour average, which were established as BACT in Permit No. PSD-FL-226 (AC54-266676) issued on September 21, 1995. EPA's RBLC shows previous CO BACT determinations for recovery boilers ranging from 200 to 3000 ppmv. These are case-by-case determinations and depend on the associated averaging period, age of the boiler, and OFA system. At Georgia-Pacific's mills, recovery boilers and other industrial boilers emit CO emissions ranging from 60 to 450 ppmv. The higher values are from older units with fewer than three levels of combustion air. The lower values are from units with three or more levels of combustion air. Actual test data for the existing No. 4 Recovery Boiler indicates that CO emissions range from 102 to 756 ppmvd @ 8% O_2. The applicant proposes to retain these current CO emission limits based on an improved overfire air system and good combustion control.

The existing No. 4 Recovery Boiler is subject to VOC standards of 0.30 lb/ton of BLS (~ 60 ppmvd @ 8% O_2) and 31.5 lb/hour established as BACT in Permit No. PSD-FL-226 (AC54-266676) issued on September 21, 1995. Review of EPA's RBLC shows previous VOC BACT determinations ranging from 2.8 to 50 ppmv. Test data shows actual VOC emissions from the existing No. 4 Recovery Boiler ranging from 0.01 to 0.083 lb/ton of BLS (~2 to 16 ppmvd @ 8% O_2, respectively). The applicant proposes a VOC emissions limit 0.20 lb/ton of BLS based on an improved OFA system and good combustion control.

Department's CO/VOC BACT Reviews

The Department is unaware of any cases where either thermal or catalytic oxidation was required for the control of CO and/or VOC emissions from recovery boilers firing BLS. The applicant proposes to retain the current CO standards of 800 ppmvd @ 8% O_2 based on a three-hour average and 400 ppmvd @ 8% O_2 based on a 24-hour average. However, the applicant has relied on short-term stack tests to demonstrate compliance with these standards. For comparison, NESHAP Subpart DDDDD establishes a CO standard of 400 ppmv based on a 30-day rolling CEMS average to ensure good combustion and serve as a surrogate for low organic HAP emissions. The Department does not consider an oxidation catalyst appropriate for the control of CO and VOC emissions from the recovery boiler due to concerns with catalyst poisoning and expected high costs to control relatively low emissions levels. Therefore, the Department accepts the proposed modification to add a fourth level of OFA as good combustion design and practices.

Test data from the Department's ARMS database shows actual CO emissions from the existing recovery boiler ranging from approximately 35 to 510 ppmvd for a three-hour test. Of the 15 tests reported, 11 test averages are below 400 ppmvd. According to the application, there is an optimum operating level for the BLS-to-air ratio. However, test results actually indicate a poor relationship between this ratio and CO emissions, possibly due to the manual control of the OFA system. The Department believes that CO emissions are controllable on a long-term average basis as provided by the industrial boiler MACT standard. Therefore, the Department establishes the following draft BACT standards.

> For the initial 180 calendar days after certifying the CEMS, CO emissions from the recovery boiler shall not exceed 800 ppmvd @ 8% O_2 and 1025.4 lb/hour based on a 30-day rolling CEMS average, excluding periods of startup and shutdown. Thereafter, CO emissions from the recovery boiler shall not exceed 400 ppmvd @ 8% O_2 and 512.7 lb/hour based on a 30-day rolling CEMS average, excluding periods of startup and shutdown.

The new CEMS-based standard will allow the demonstration of continuous compliance, ensure the use of good combustion practices, and provide useful data for the operator controlling the system. The purposes of the initial standard is to provide sufficient time for the operators to gain experience and establish good operating practices with the new four-level OFA system. The new standard will replace the previous CO standards and is believed to be more stringent due to the continuous compliance demonstration.

For the No. 4 Recovery Boiler, the applicant proposes VOC standards of 0.20 lb/ton of BLS and 21.0 lb/hour. Test data from the Department's ARMS database shows actual VOC emissions ranging from 0.01 to 0.083 lb/ton of BLS. Of the 14 tests submitted, all have been below 0.10 lb/ton BLS. The addition of a fourth level of OFA is intended to provide improved combustion control. In addition, low CO emissions generally mean low VOC emissions. Therefore, the Department establishes the following draft BACT standards.

> As determined by EPA Method 25A, VOC emissions shall not exceed 0.20 lb/ton of BLS and 21.0 lb/hour (THC determined as methane) based on the average of three test runs.

Compliance with the VOC standards shall be demonstrated by conducting an initial stack test. Because emissions are expected to be low and the CO CEMS will ensure efficient combustion, subsequent tests shall be conducted prior to renewal of the operation permit or when the Department requests a special test pursuant to Rule 62-297.310(7)(b), F.A.C. The CO standard serves as a surrogate standard for VOC.

6. OTHER PERMIT CONDITIONS

Previous Air Construction Permits

This permit supplements all previous permits issued for the affected emissions units. The conditions of this permit satisfy the applicable requirements for the emissions increases related to the project. These conditions supersede corresponding similar conditions specified in previous air construction permits. However, if not specifically regulated by this permit, other standards and permit requirements from previous air construction permits remain valid. The affected emissions units remain subject to all applicable standards and regulations as regulated by the Title V air operation permit.

No. 4 Power Boiler (EU-014)

The No. 4 Power Boiler is not currently in operation. Emissions decreases from the permanent shutdown of this unit were used in the PSD netting analysis to avoid PSD preconstruction review for SAM, SO_2, and TRS emissions. Therefore, the draft permit requires the permanent shutdown of the No. 4 Power Boiler.

No. 5 Power Boiler (EU-015)

<u>Existing Applicable Requirements</u>

The draft permit establishes a NO_X standard of 0.185 lb/MMBtu of heat input and 71.1 lb/hour to avoid PSD review pursuant to Rule 62-212.400(12), F.A.C. Unless otherwise specified by this permit, the No. 5 Power Boiler also remains subject to the following existing applicable requirements, which are specified in the current Title V air operation permit.

- Rule 62-296.404, F.A.C. for Kraft Pulp Mills;
- Rule 62-296.405, F.A.C. for Fossil Fuel Steam Generators with More than 250 MMBtu per hour of Heat Input;
- 40 CFR 63, NESHAP Subpart S for Kraft Pulp Mills; and
- 40 CFR 63, NESHAP Subpart DDDDD for Industrial Boilers.
- On July 2, 2004, the Department issued Permit No. 1070005-024-AC as a Pollution Control Project (PCP) pursuant to Rule 62-212.400(2)(a)2.b, F.A.C. That permit specified the strategy for complying with the applicable requirements of the MACT standards in NESHAP Subpart S in 40 CFR 63. That permit authorizes the No. 5 Power Boiler to destroy dilute non-condensable gases (DNCGs) from the high-volume, low-concentration (HVLC) system, which include emissions from brown stock washers, pressure knotters, the bleach plant pre-washer, the oxygen delignification system, and softwood/hardwood high density storage tanks. The DNCGs are introduced with the primary fuel, directed into the flame zone, or added with the combustion air. Optionally, the DNCGs may also be directed to the No. 4 Combination Boiler, which shares common permit conditions with the No. 5 Power Boiler. Permit No. 1070005-024-AC limits SO_2 emissions to 82.6 lb/hour and 236.3 tons per year from the destruction of DNCGs in any combination of the No. 4 Combination Boiler and the No. 5 Power Boiler. This current permitting action does not affect the previous authorization for destroying DNCGs.

<u>Discussion of PM Emissions and Testing</u>

The No. 5 Power Boiler is subject to Rule 62-296.405, F.A.C. because it fires fossil fuel at a rate of more than 250 MMBtu per hour of heat input. After conversion to natural gas, this unit will only be subject to the standards in this rule for visible emissions, PM and the requirement to monitor the ambient effects of SO_2 emissions as required by the Department. The PM standard is 0.1 lb per MMBtu of heat input. Natural gas contains negligible amounts of sulfur and ash, is efficiently combusted in a boiler, and is expected to result in PM emissions of less than 10% of the standard specified in this rule. For these reasons, the applicant proposes to remove the existing electrostatic precipitator used to remove ash generated from the combustion of residual fuel oil. The applicant proposes to use the existing electrostatic precipitator to reduce PM emissions from the No. 4 Combination Boiler.

In accordance with an alternate sampling procedure (ASP No. 97-B-01) dated March 17, 1997, the Department determined that PM testing is not required for boilers when firing natural gas. The firing of natural gas and compliance with the opacity standard is sufficient to demonstrate compliance with the PM standard. In accordance with Rule 62-297.310(7)(b), F.A.C., the Department may require special compliance tests if it has good reason to believe that the PM standard is being violated.

No. 4 Lime Kiln (EU-017)

Existing Applicable Requirements

Unless otherwise specified by this permit, the No. 4 Lime Kiln remains subject to the following existing applicable requirements, which are specified in the current Title V air operation permit.

- Rule 62-296.404, F.A.C. for Kraft Pulp Mills;
- 40 CFR 63, NESHAP Subpart S for Kraft Pulp Mill; and
- Permit No. PSD-FL-171.

New Requirements Requested by Applicant

This project is based on a PSD netting analysis. In accordance with Rule 62-212.400(12) (Source Obligation), F.A.C., the applicant requested the following limitations to avoid PSD preconstruction review for SO_2 and TRS emissions.

- The maximum sulfur content of oil is 2.35% by weight.
- No more than 8,173,080 gallons of oil shall be fired during any consecutive 12 months.
- As determined by the existing CEMS, TRS emissions shall not exceed 25.1 tons per year based on a 12-month rolling CEMS total.

No. 4 Recovery Boiler (EU-018)

Existing Applicable Requirements

Unless otherwise specified by this permit, the No. 4 Recovery Boiler remains subject to the following existing applicable requirements, which are specified in the current Title V air operation permit.

- Rule 62-296.404, F.A.C. for Kraft Pulp Mills;
- NSPS Subpart BB in 40 CFR 63 for Recovery Combustion Sources at Kraft Pulp Mills;
- NESHAP Subpart MM in 40 CFR 63 for Recovery Combustion Sources at Kraft Pulp Mills; and
- Permit Nos. PSD-FL-171 and PSD-FL-226.

New Requirements Requested by Applicant

This project is based on a PSD netting analysis. In accordance with Rule 62-212.400(12) (Source Obligation), F.A.C., the applicant requested the following limitations to avoid PSD preconstruction review for SO_2 and TRS emissions.

- The maximum sulfur content of oil is 2.35% by weight.
- No more than 7,860,640 gallons of oil shall be fired during any consecutive 12 months. (This limits oil firing to an annual capacity factor of less than 10% of the total heat input rate to the unit. It represents less than 17% of the maximum annual firing capabilities of the oil burners.)
- As determined by data collected from the existing CEMS, TRS emissions shall not exceed 34.2 tons per year based on a 12-month rolling CEMS total.
- As determined by data collected from the existing CEMS, SO_2 emissions shall not exceed 153.9 tons per year based on a 12-month rolling CEMS total.

No. 4 Combination Boiler

The PSD netting analysis included the project to modify the No. 4 Combination Boiler. Emissions increases from the No. 4 Combination Boiler were included in the required air quality analysis for this project. In addition, Project No. 1070005-045-AC will determine BACT for CO, NO_X, PM, and VOC from the No. 4 Combination Boiler. The pending project is based on the following oil firing restrictions: residual oil with a maximum sulfur content of 2.35% by weight; and a limit of 5.1 million gallons of oil fired during any consecutive 12 months.

- The maximum sulfur content of oil is 2.35% by weight.
- No more than 5,100,000 gallons of oil shall be fired during any consecutive 12 months. (This limits oil firing to an annual capacity factor of less than 19% of the total heat input rate to the unit. It represents approximately 20% of the maximum annual firing capabilities of the oil burners.)

7.0 AIR QUALITY ANALYSIS

Introduction

CO, NO_2, PM_{10} and VOC are PSD pollutants subject to the preconstruction review requirements for this project. CO, NO_2, and PM_{10} are criteria air pollutants with national and state ambient air quality standards (AAQS), significant impact levels, and de minimis preconstruction monitoring concentrations. In addition, NO_2 and PM_{10} have additional requirements for PSD increments. For the criteria pollutant ozone, VOC emissions are reviewed for significant impact levels and de minimis preconstruction monitoring concentrations. Therefore, the following analyses were required for this project.

- An analysis of existing air quality for NO_2, PM_{10} and VOC;
- A significant impact analysis for CO, NO_2, PM_{10} and VOC;
- A PSD increment analysis for NO_2 and PM_{10};
- An AAQS analysis for NO_2 and PM_{10}; and
- An analysis of impacts on soils, vegetation, and visibility and growth-related impacts to air quality.

The analysis of existing air quality generally relies on preconstruction monitoring data collected with EPA-approved methods. The significant impact analysis, PSD increment analysis, and AAQS analysis depend on air quality dispersion modeling carried out in accordance with EPA and Department guidelines.

Analysis of Existing Air Quality

Preconstruction ambient air quality monitoring data is required for all significant PSD pollutants to determine existing ambient concentrations unless exempt by rule or the data requirements can be satisfied otherwise. Projects may be exempt from the requirement to develop site-specific preconstruction monitoring data if one of the following conditions is met: the maximum predicted ambient impact from the emissions increase due to the project is less than the corresponding regulatory de minimis ambient concentration; or, the existing ambient concentration is less than the corresponding regulatory de minimis ambient concentration. No de minimis ambient concentration is provided for ozone. Instead the net VOC emissions increase is compared to a de minimis annual emission rate of 100 tons per year.

Whether or not preconstruction ambient monitoring is required, it may be necessary to determine existing ambient background concentrations for each significant PSD pollutant subject to an AAQS. Ambient background concentrations represent the air quality impacts of all sources not included in the modeling analysis. The ambient background concentrations are added to the ambient impacts from modeled sources to determine total ambient impacts. Ambient background concentrations may be determined from the required preconstruction site-specific ambient air quality monitoring data or from existing representative ambient monitoring data collected from nearby qualified monitoring stations.

The following table compares the maximum predicted air quality impacts from the project with the regulatory de minimis concentrations.

MAXIMUM PREDICTED AIR QUALITY IMPACTS FROM PROJECT COMPARED TO THE REGULATORY DE MINIMIS CONCENTRATIONS				
Pollutant	**Averaging Time**	**Maximum Predicted Impact ($\mu g/m^3$)**	**De Minimis Concentration ($\mu g/m^3$)**	**Impact Greater than De Minimis? (Yes/No)**
PM_{10}	24-hr	12	10	Yes
CO	8-hr	79	575	No
NO_2	Annual	2	14	No
VOC	Annual Emissions Rate	389 tons/year	100 tons/year	Yes

As shown in the table, CO and NO_2 impacts are predicted to be less than the regulatory de minimis levels and preconstruction monitoring is not required for these pollutants. Because PM_{10} and VOC emissions are predicted to be greater than the regulatory de minimis levels, preconstruction monitoring data is required for these pollutants. Although exempt from preconstruction monitoring requirements, it will be necessary to determine existing ambient background concentrations for NO_2. To satisfy the ambient monitoring data requirements, the applicant proposes to use the following representative data collected from nearby stations that are part of the state's monitoring network: data from the existing ozone monitors located in urban Alachua and Duval counties to the west and north of the project; data from an existing PM_{10} monitor in Putnam County near the project site; and data from an existing NO_2 monitor in the Jacksonville area. As shown in the following table, the ambient monitoring data shows no violations of any AAQS.

EXISTING PRECONSTRUCTION AND BACKGROUND CONCENTRATIONS			
Pollutant	**Averaging Time**	**Background ($\mu g/m^3$)**	**AAQS ($\mu g/m^3$)**
PM_{10}	Annual	26	50
	24-hour	62	150
NO_2	Annual	27	100

Since an AAQS analysis is required for NO_2 and PM_{10}, the above ambient background concentrations for these pollutants will be used in the analysis.

Models and Meteorological Data Used in Significant Impact, PSD Increment and AAQS Analyses

Good Engineering Practice Stack Height

Good Engineering Practice (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). The stacks for this project will be less than the corresponding GEP stack heights. Therefore, the potential for building downwash was considered in the modeling analysis for this project.

PSD Class II Area Model

AERMOD, the air dispersion model approved by the American Meteorological Society and the EPA, was used to evaluate the air quality impacts from the proposed project and other existing major facilities. In November, 2005, the EPA promulgated AERMOD as the preferred regulatory model for predicting pollutant concentrations within 50 km from a source. AERMOD is a replacement for the Industrial Source Complex Short-Term Model (ISCST3). The AERMOD model calculates hourly concentrations based on hourly meteorological data. 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). AERMOD can predict pollutant concentrations for annual, 24-hour, 8-hour, 3-hour and 1-hour averaging periods. 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 corresponding GEP stack height.

Meteorological data used in the AERMOD model consisted of a concurrent 5-year period of hourly surface weather observations and twice-daily upper air soundings from the Jacksonville International Airport. The 5-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.

Because five years of data are used in AERMOD, the highest-second-high (HSH) short-term predicted concentrations were compared with the appropriate AAQS or PSD increment. For the annual averages, the highest predicted yearly average was compared with the standards. For determining the project's significant impact area in the vicinity of the facility, and for determining if significant impacts occur in any PSD Class I area, both the highest short-term predicted concentrations and the highest predicted yearly averages were compared to their respective significant impact levels.

In reviewing this permit application, the Department has determined that the application 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.

PSD Class I Area Model

The PSD Class I areas within 200 km of the project are the Okefenokee National Wilderness Area (NWA), the Chassahowitzka NWA and the Wolf Island NWA. Since these Class I areas are greater than 50 km from the proposed facility, long-range transport modeling was required for the Class I impact assessment. The California Puff (CALPUFF) dispersion model was used to evaluate the potential impacts on the PSD Class I increments and on the Air Quality Related Values (AQRV) for regional haze, nitrogen deposition and sulfur deposition. CALPUFF 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 was processed by the California Meteorological (CALMET) model. The CALMET model utilizes data from multiple meteorological stations and produces a 3-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. For 2001 through 2003 and a 4-km Florida domain, meteorological data were obtained and processed for use in the Class I analyses. The CALMET wind field and the CALPUFF model options used were consistent with the suggestions of the federal land managers.

Receptor Grids Used in PSD Increment Analysis and AAQS Analysis

For the PSD Class II increment and AAQS analyses, receptor grids normally are based on the size of the significant impact area for each pollutant. The sizes of the significant impact areas for the required PM_{10} and NO_2 analyses were 1 kilometer or less. Over 2000 receptors were placed along the restricted property line of the facility and out to 4 km from the facility.

Significant Impact Analysis

Preliminary modeling is conducted using only the proposed project's worst-case emission scenario for each pollutant and applicable averaging time. The Okefenokee NWA is the closest PSD Class I area and is located 108 km from the project at its closest point. The other PSD Class I areas located within 200 km of the facility are the Chassahowitzka NWA located 137 km southwest of the project and the Wolf Island NWA located 186 km to the north of the project. A total of 180, 113 and 30 receptors were placed in the Okefenokee NWA, Chassahowitzka NWA and Wolf Island NWA PSD Class I areas, respectively.

For each significant PSD pollutant that requires a PSD increment and/or AAQS analysis, a preliminary significant impact modeling analysis is conducted. The results of this analysis compares the maximum predicted impacts from the project with the corresponding regulatory significant impact levels to determine whether the project could have a significant impact in any PSD Class II area in the vicinity of the project or in any nearby PSD Class I area. If the maximum predicted impact is less than the regulatory significant impact level, the project is considered to have no significant impact on the AAQS or PSD increments, and the requirement to conduct a PSD air quality analysis is satisfied. However, if the maximum predicted impact is greater than the regulatory significant impact level, a full impact modeling analysis must be conducted. The full impact modeling analysis considers not only impacts from the project, but also impacts from other nearby major sources as well as background concentrations representing all other point and area source contributions. The following tables show the predicted maximum impacts due to the project for the Class I and II areas as well as the radius of impact for any significant Class II impact.

MAXIMUM PREDICTED PROJECT IMPACTS COMPARED TO THE SIGNIFICANT IMPACT LEVELS FOR THE PSD CLASS II AREAS IN THE VICINITY OF THE FACILITY					
Pollutant	**Averaging Time**	**Maximum Predicted Impact ($\mu g/m^3$)**	**Significant Impact Level ($\mu g/m^3$)**	**Significant Impact?**	**Radius of Significant Impact (km)**
PM_{10}	Annual	1.4	1	Yes	1
	24-hr	12	5	Yes	1
CO	8-hr	67	500	No	NA
	1-hr	79	2,000	No	NA
NO_2	Annual	2	1	Yes	1
VOC	Annual Rate	407 tons/year	100 tons/year	Yes	NA

MAXIMUM PREDICTED PROJECT IMPACTS COMPARED TO THE SIGNIFICANT IMPACT LEVELS FOR THE PSD CLASS I AREAS				
Pollutant	**Averaging Time**	**Maximum Predicted Impact ($\mu g/m^3$)**	**Significant Impact Level ($\mu g/m^3$)**	**Significant Impact? (ug/m^3)**
PM_{10}	Annual	0.001	0.2	No
	24-hr	0.01	0.3	No
NO_2	Annual	0.003	0.1	No

As shown in the tables, the maximum predicted CO impacts due to the project are less than the regulatory significant impact levels for the Class II areas in the vicinity of the project. Also, the maximum predicted impacts of PM_{10} and NO_2 due to the project are less than the regulatory significant impact levels for the Class I areas. Therefore, no further air dispersion modeling was required for these pollutants in these areas. However, the maximum predicted impacts of PM_{10} and NO_2 due to the proposed project are greater than the PSD Class II significant impact levels in the vicinity of the facility. Therefore, the applicant was required to conduct a full modeling analysis to determine PM_{10} and NO_2 impacts within the applicable significant impact area for comparison to the AAQS and the PSD increments. The significant impact area is determined by the predicted radius of significant impact. These analyses are provided in the following sections.

The table also shows that potential VOC emissions increases are above the annual emission rate threshold of 100 tons per year established for the pollutant ozone. Since no stationary point source models are available and approved for use in predicting ozone impacts, the applicant presented potential VOC emissions increases to the Department and discussed available options to predict potential impacts associated with the VOC emissions and formation of ozone. Based on the available information, the Department has determined that the use of a regional model that incorporates the complex chemical mechanisms for predicting ozone formation is not suitable for this project. No further analysis is required for this pollutant.

PSD Increment Analysis

The PSD increment represents the amount that new sources in an area may increase the ambient concentrations of a pollutant from the baseline concentration. For PM_{10} and SO_2, the PSD increments were established in 1977 based on major sources of PM_{10} and SO_2 emissions for the baseline year of 1975. For NO_2, the PSD increment was established in 1988 based on major sources of NO_2 emissions for the baseline year of 1988. The emission rates input into the model for predicting increment consumption are based on maximum emissions from increment-consuming sources at the facility as well as all other increment-consuming sources in the vicinity of the facility. The following table shows the maximum predicted PM_{10} and NO_2 increments for the PSD Class II areas consumed by this project and all other increment-consuming sources in the vicinity of the project. As shown, the maximum predicted impacts are less than the allowable increments.

PSD CLASS II INCREMENT ANALYSIS				
Pollutant	**Averaging Time**	**Maximum Predicted Impact ($\mu g/m^3$)**	**Allowable Increment ($\mu g/m^3$)**	**Impact Greater Than Allowable Increment?**
PM_{10}	Annual	0	17	No
	24-hour	22	30	No
NO_2	Annual	3	25	No

AAQS Analysis

For pollutants subject to an AAQS review, the total impact on ambient air quality is obtained by adding a "background concentration" to the maximum predicted concentration. The purpose of the background concentration is to account for all other point and area sources that are not explicitly modeled. The results of the AAQS analysis are summarized in the table below. As shown, the proposed project is not expected to cause or significantly contribute to a violation of any AAQS.

MAXIMUM AMBIENT AIR QUALITY IMPACTS						
Pollutant	**Averaging Time**	**Modeled Sources ($\mu g/m^3$)**	**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	62	104	150	No
NO_2	Annual	10	27	37	100	No

Ozone Discussion

This project results in PSD-significant increases of NO_X and VOC emissions, which are ozone precursors. A demonstration that these emissions increases will not cause or contribute to any predicted violations of the ozone standards would require the use of a very sophisticated and expensive air dispersion model and computer system. Such an analysis would need to be run for the entire region with key inputs to the model from traffic, power plants, other industrial sources, and complex meteorology. Potential emissions increases from this project are 405 tons per year of NO_X and 418 tons per year of VOC. At these rates, the contribution of these emissions is not considered significant in terms of impacts to the overall regional ozone concentrations. The uncertainty of the impacts predicted by a regional ozone model would likely be greater than the impacts contributed by this project.

Additional Impacts Analysis

Impacts on Soils, Vegetation, Wildlife and Visibility

The maximum predicted ambient concentrations of CO, NO_X and PM_{10} due to the proposed project, including all other nearby sources, are less than corresponding AAQS, which are designed to protect both the public health and welfare. As such, this project is not expected to have a harmful impact on soils and vegetation in any PSD Class II area in the vicinity of the project. The applicant conducted an analysis for air quality related values (AQRV) for the nearby PSD Class I area. No significant impacts on this area are expected. The applicant conducted a regional haze analysis using the long-range transport model CALPUFF for the nearby PSD Class I areas. No significant visibility impacts are predicted in the PSD Class I areas. The CALPUFF model was also used to predict total nitrogen deposition rates on the PSD Class I areas. The maximum predicted deposition rates were less than the threshold levels recommended by the federal land manager.

Growth-Related Air Quality Impacts

The proposed modification will not substantially change employment, population, housing, commercial development, or industrial development in the area. Therefore, no significant air quality impacts are predicted.

Conclusion

The applicant provided reasonable assurance that the proposed project will not cause or significantly contribute to a violation of any AAQS or PSD increments as described in the application, summarized in this report, and subject to the specific conditions of the draft permit.

8. PRELIMINARY DETERMINATION

The Department makes a preliminary determination that the proposed project will comply with all applicable state and federal air pollution regulations as conditioned by the draft permit. This determination is based on a technical review of the complete application, reasonable assurances provided by the applicant, and the conditions specified in the draft permit. Bruce Mitchell is the project engineer responsible for reviewing the application and drafting the permit documents. Cleve Holladay is the staff meteorologist responsible for reviewing the ambient air quality analyses. Jeff Koerner, P.E. 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. 1070005-038-AC
PSD No. PSD-FL-380
Georgia-Pacific Palatka Mill
PSD Modification
SIC Nos. 2611 and 2621
Permit Expires: November 1, 2009

FACILITY AND LOCATION

Georgia-Pacific Consumer Operations LLC operates the Palatka Mill, which is a Kraft process pulp and paper mill 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. This permit requires permanent shutdown of the No. 4 Power Boiler and authorizes modifications to the No. 5 Power Boiler, No. 4 Lime Kiln, No. 4 Recovery Boiler, and No. 4 multiple effect evaporator set.

STATEMENT OF BASIS

This air pollution construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), and Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.) and Title 40, Parts 60 and 63 of the Code of Federal Regulations (CFR). 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).

CONTENTS

(DRAFT)

Joseph Kahn, Director
Division of Air Resource Management

Effective Date

FACILITY DESCRIPTION

Georgia-Pacific operates an existing paper and pulp mill in Palatka, Florida 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 fuel oil and natural gas.

REGULATORY CLASSIFICATION

- 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.
- The facility is a major stationary source subject to the Prevention of Significant Deterioration (PSD) of Air Quality.

PROJECT DESCRIPTION

This permit authorizes the following major modifications: permanent shutdown of the No. 4 Power Boiler; conversion of the No. 5 Power Boiler to natural gas; replacement of the hot-end section and cooler tubes for the No. 4 Lime Kiln; extensive tube replacement and modification of the combustion air system (including the addition of a fourth level of overfire air) for the No. 4 Recovery Boiler; and the addition of a crystallizer with associated storage/flash tank and modifications to the two concentrators associated with the No. 4 multiple effect evaporator set. This permit affects the following emissions units.

ID	Emission Unit Description
014	No. 4 Power Boiler
015	No. 5 Power Boiler
016	No. 4 Combination Boiler
017	No. 4 Lime Kiln
018	No. 4 Recovery Boiler
xxx	Noncondensable Gas System including the No. 4 Multiple Effect Evaporator (MEE) Set

The permittee conducted a PSD netting analysis based on contemporaneous emissions increases and decreases to avoid PSD preconstruction review for sulfur dioxide (SO_2), sulfuric acid mist (SAM), and total reduced sulfur (TRS). The project is subject to PSD preconstruction review for carbon monoxide (CO), nitrogen oxides (NO_X), particulate matter (PM), and volatile organic compounds (VOC). For this permit, the Department determined the Best Available Control Technology (BACT) for the following units: the No. 5 Power Boiler (CO and VOC); the No. 4 Lime Kiln (CO, NO_X, PM, and VOC); and the No. 4 Recovery Boiler (CO, NO_X, PM, and VOC). The No. 4 Combination Boiler is currently under PSD preconstruction review in Project No. 1070005-045-AC for CO, NO_X, PM, and VOC. Throughout this permit, particulate matter emissions are referred to as PM emissions, which serve as a surrogate for regulating $PM_{2.5}$ and PM_{10} emissions.

RELEVANT DOCUMENTS

The following relevant documents are not a part of this permit, but helped form the basis for this permitting action: the permit application and additional information received to make it complete; the draft permit package including the Department's Technical Evaluation and Preliminary Determination; publication and comments; the Department's Final Determination; previous air construction permits; and the current Title V air operation permit.

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

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

3. Appendices: The following Appendices are attached as part of this permit:
   a. Appendix A. Citation Formats
   b. Appendix B. General Conditions
   c. Appendix C. Common Conditions
   d. Appendix D. Standard Testing Requirements
   e. Appendix E. Standard Continuous Monitoring Requirements
   f. Appendix F. Final BACT Determinations and Emissions Summary
   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. To apply for a Title V operation permit, the applicant shall submit the appropriate application form, compliance test results, and such additional information as the Department may by law require. The application shall be submitted to the Air Resource Section of the Department's Northeast District Office. [Rules 62-4.030, 62-4.050, 62-4.220, and Chapter 62-213, F.A.C.]

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

A. No. 4 Power Boiler and No. 4 Combination Boiler

This subsection of the permit addresses the following emissions units.

ID	Emission Unit Description
014	No. 4 Power Boiler
016	No. 4 Combination Boiler

{Permitting Note: In accordance with Rule 62-212.400 (PSD), F.A.C., the permittee conducted a PSD netting analysis that used contemporaneous emissions decreases from the permanent shutdown of the No. 4 Power Boiler to avoid PSD preconstruction review for SO_2, SAM, and TRS.}

PERFORMANCE RESTRICTIONS

1. Shutdown: The No. 4 Power Boiler is currently not in operation. As part of this project, the permittee shall permanently shutdown the No. 4 Power Boiler. Within 90 days of issuance of this permit, the permittee shall provide written notice of the permanent shutdown of this unit. [Rules 62-4.070(3) and 62-212.400(12), F.A.C.]
2. PSD Review: The permittee plans to modify the No. 4 Combination Boiler. Although a review is being conducted under Project No. 1070005-045-AC, emissions increases from this unit were included in the PSD netting analysis. That project is also subject to PSD preconstruction review for CO, NO_X, PM, and VOC emissions. [Rule 62-212.400 (PSD), F.A.C.]
3. Oil Firing – No. 4 Combination Boiler: The maximum sulfur content of oil is 2.35% by weight. No more than 5,100,000 gallons of oil shall be fired during any consecutive 12 months. The permittee shall keep records on a monthly basis to ensure compliance with the oil firing restriction. *{Permitting Note: This limits oil firing to an annual capacity factor of approximately 21% of the total maximum heat input rate to the unit.}*

This subsection of the permit addresses the following emissions unit.

ID	Emission Unit Description
015	**No. 5 Power Boiler**: This unit fires natural gas to produce steam and power for use at the mill. The permitted capacity is 568.9 MMBtu per hour of heat input to produce approximately 445,200 lb/hour of steam. CO, NO_X and VOC emissions are controlled by the burner design and efficient combustion of natural gas, which also minimizes PM/PM_{10}, SAM and SO_2 emissions. At permitted capacity, the exhaust gas flow rate is 135,400 dscfm at 10% oxygen with an exit temperature of 500° F. Exhaust gases exit a stack that is 9.0 feet in diameter and 156.5 feet tall.

{Permitting Note: In accordance with Rule 62-212.400 (PSD), F.A.C., the above emission unit is subject to BACT determinations for CO and VOC emissions, which are presented in Appendix E of this permit.}

EXISTING APPLICABLE REQUIREMENTS

1. State Rule for Kraft Pulp Mills: The No. 5 Power Boiler is subject to the applicable requirements of Rule 62-296.404, F.A.C. for Kraft Pulp Mills.
2. State Rule for Large Boilers: The No. 5 Power Boiler is subject to the applicable requirements of Rule 62-296.405, F.A.C. for Fossil Fuel Steam Generators with More than 250 MMBtu per hour of Heat Input.
3. NESHAP Subpart S for Kraft Pulp Mills: The No. 5 Power Boiler is subject to the applicable MACT requirements in NESHAP Subpart S in 40 CFR 63.
4. NESHAP Subpart DDDDD for Industrial Boilers: The No. 5 Power Boiler is subject to the applicable requirements for existing units specified in NESHAP Subpart DDDDD of 40 CFR 63 for Industrial, Commercial, and Institutional Boilers and Process Heaters.
5. PCP Exemption: This current permitting action does not affect the previous authorization of Permit No. 1070005-024-AC issued on July 2, 2004 for destroying DNCGs issued as a Pollution Control Project (PCP) pursuant to Rule 62-212.400(2)(a)2.b, F.A.C. That permit specified the strategy for complying with the applicable requirements of the MACT standards in NESHAP Subpart S in 40 CFR 63. That permit authorizes the No. 5 Power Boiler to destroy dilute non-condensable gases (DNCGs) from the high-volume, low-concentration (HVLC) system, which include emissions from brown stock washers, pressure knotters, the bleach plant pre-washer, the oxygen delignification system, and softwood/hardwood high density storage tanks. The DNCGs are introduced with the primary fuel, directed into the flame zone, or added with the combustion air. Optionally, the DNCGs may also be directed to the No. 4 Combination Boiler, which shares common permit conditions with the No. 5 Power Boiler. Permit No. 1070005-024-AC limits SO_2 emissions to 82.6 lb/hour and 236.3 tons per year from the destruction of DNCGs in any combination of the No. 4 Combination Boiler and the No. 5 Power Boiler. [Permit No. 1070005-024-AC; Rule 62-212.400 (PSD), F.A.C.]

MODIFICATIONS AND CAPACITIES

6. Natural Gas Conversion: The permittee shall convert the No. 5 Power Boiler to a natural gas-fired boiler. The permittee shall remove the oil burners and install natural gas burners that will achieve the emissions standards and capacities specified in this permit. If necessary to achieve the NO_X standard, the permittee is authorized to install a flue gas recirculation system consisting of the necessary fans, ductwork, and dampers. The conversion to natural gas shall be completed by April 1, 2008. Once converted to natural gas, the existing electrostatic precipitator may be removed from the No. 5 Power Boiler. It may be used as additional fields for controlling PM emissions from the No. 4 Combination Boiler. [Application No. 1070005-038-AC; Rule 62-212.400 (PSD), F.A.C.]

7. Authorized Fuels: The No. 5 Power Boiler shall be converted to fire pipeline natural gas as the sole fuel. After completing the project, the firing of oil is prohibited. As a control device, the No. 5 Power Boiler is authorized to destroy dilute non-condensable gases (DNCGs) from the high-volume, low-concentration (HVLC) system *{Permitting Note: The No. 5 Power Boiler currently fires oil with a maximum sulfur content of 2.35% by weight. After conversion to natural gas, potential annual SO_2 emissions will be less than 2 tons per year and potential SAM and TRS emissions will be negligible.}* [Application No. 1070005-038-AC; Rule 62-212.400 (PSD), F.A.C.]

8. Permitted Capacity: After converting to natural gas, the permitted capacity of the No. 5 Power Boiler shall be 568.9 MMBtu of heat input per hour based on a 24-hour average. At this heat input rate, the unit will produce approximately 445,200 lb/hour of steam based on a 24-hour average. Hours of operation are not restricted (8760 hours/year). [Application No. 1070005-038-AC; Rules 62-210.200 (PTE) and 62-212.400 (PSD), F.A.C.]

EMISSIONS AND PERFORMANCE STANDARDS

9. CO Standard: As determined by EPA Method 10, CO emissions shall not exceed 0.185 lb per MMBtu of heat input and 105.2 lb/hour based on the average of three test runs. The CO standard serves as a surrogate standard for minimizing VOC emissions as a result of the efficient combustion of natural gas. *{Permitting Note: VOC emissions are expected to be less than 14 tons per year from firing natural gas.}* [Rule 62-212.400 (BACT), F.A.C.]

10. NO_X Standard: As determined by EPA Method 7E, NO_X emissions shall not exceed 0.125 lb/MMBtu of heat input and 71.1 lb/hour based on the average of three test runs. [Rules 62-4.070(3) and 62-212.400(12), F.A.C.]

COMPLIANCE MONITORING AND TESTING

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

12. 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.]

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

Method	Description of Method and Comments
1-4	Traverse Points, Velocity and Flow Rate, Gas Analysis, and Moisture Content
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources {Note: The method shall be based on a continuous sampling train.}
19	Determination of Sulfur Dioxide Removal Efficiency and Particulate Matter, Sulfur Dioxide, and Nitrogen Oxides Emission Rates (Optional F-factor method may be used to determine flow rate and gas analysis to calculate mass emissions in lieu of Methods 1-4.)

Tests shall also be conducted in accordance with the requirements specified in Appendix D (Standard Testing Requirements) of this permit. The above methods are described in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C. [Rules 62-204.800 and 62-297.100, F.A.C.; 40 CFR 60, Appendix A]

14. Initial Stack Tests: In accordance with the specified test methods, the No. 5 Power Boiler shall be tested to demonstrate compliance with the emissions standards for CO and NO_X. Initial stack tests for these pollutants shall be conducted within 60 days after achieving permitted capacity, but not later than 180 days after initial startup on natural gas. All initial tests shall be conducted with the emissions unit operating at 90% to 100% of the permitted capacity; otherwise, this permit shall be modified to reflect the true maximum capacity as constructed. The Department may require the permittee to repeat some or all of the initial stack tests after major replacement or major repair of emissions-related equipment. [Rules 62-4.070(3), 62-212.400(PSD) and 62-297.310(7), F.A.C.]

15. Annual Stack Tests: During each federal fiscal year (October 1st to September 30th), the No. 5 Power Boiler shall be tested to demonstrate compliance with the emission standards for CO and NO_X. Testing of emissions shall be conducted with the emissions unit operating at 90% to 100% of the permitted capacity. If it is impractical to test within this range, the emissions unit may be tested at less than 90% of the maximum permitted capacity. In this case, subsequent emissions unit operation is limited to 110% of the tested 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. *{Permitting Note: Additional tests may be required by other applicable requirements.}* [Rules 62-4.070(3), 62-212.400(PSD) and 62-297.310(7), F.A.C.]

16. Fuel Monitoring: The permittee shall install equipment to continuously monitor the flow rates of natural gas and DNCGs to the No. 5 Power Boiler. This may consist of fuel flow meters with integrators to monitor each flow rate. [Rules 62-4.070(3) and 62-212.400(12), F.A.C.]

RECORDS AND REPORTS

17. Test Reports: For each required test, the permittee shall file a report with the Compliance Authority on the results of each required test in accordance with the requirements of Rule 62-297.310(8), F.A.C.

18. Monitoring of Capacity: The permittee shall monitor and record the operating rate of the No. 5 Power Boiler on a daily average basis considering the number of hours of operation during each day. This shall be achieved through monitoring daily rates of consumption and heat content of natural gas. The information shall be documented and recorded for each day of operation. Records shall be made available to the Compliance Authority upon request. [Rule 62-4.070(3), F.A.C.]

C. No. 4 Lime Kiln

This subsection of the permit addresses the following emissions unit.

ID	Emission Unit Description
017	**No. 4 Lime Kiln**: This unit recalcines the spent lime cake (calcium carbonate) to produce the quicklime (calcium oxide), which is used to convert the green liquor to cooking liquor. The kiln fires residual fuel oil and has a maximum processing rate of 41.5 tons of material per hour based on a 24-hour average. Particulate matter emissions are controlled by a cyclonic dust collector followed by a wet venturi scrubber. TRS emissions, scrubber pressure drop, and scrubber flow rate are continuously monitored and recorded. At permitted capacity, the exhaust gas flow rate is 54,200 dscfm at 10% oxygen with an exit temperature of 164° F. Exhaust gases exit a stack that is 4.4 feet in diameter and 131 feet tall.

{Permitting Note: In accordance with Rule 62-212.400 (PSD), F.A.C., the above emission unit is subject to BACT determinations for CO and VOC emissions, which are presented in Appendix E of this permit.}

EXISTING APPLICABLE REQUIREMENTS

1. State Rule for Kraft Pulp Mills: The No. 4 Lime Kiln remains subject to the applicable requirements of Rule 62-296.404, F.A.C. for Kraft Pulp Mills.
2. NESHAP Subpart MM for Kraft Pulp Mills: The No. 4 Lime Kiln remains subject to the applicable MACT requirements in NESHAP Subpart S in 40 CFR 63.
3. PSD Permit: Unless otherwise specified by condition in this permit, the No. 4 Lime Kiln remains subject to the applicable requirements of Permit No. PSD-FL-171.

MODIFICATIONS AND CAPACITIES

4. Kiln Modification: For the No. 4 Lime Kiln, the permittee is authorized to replace approximately 62 feet of the hot-end kiln shell and all 10 coolers located in this section. The new coolers will be mounted with an improved bracket design to prevent stress cracks underneath the coolers. [Rule 62-210.300(1), F.A.C.]
5. Permitted Capacity: The maximum processing rate of the No. 4 Lime Kiln is 41.5 tons of material per hour based on a 24-hour average. This corresponds to a maximum production rate of 19.4 tons per hour of quicklime. There is no restriction on the hours of operation (8760 hours/year). At permitted capacity, the maximum flue gas flow rate is 54,200 dscfm @ 10% oxygen. The lime kiln typically operates at flue gas oxygen contents in the range of 4% to 6% by volume. [Application No. 1070005-038-AC; Rule 62-210.200 (PTE), F.A.C.]
6. Authorized Fuels: The No. 4 Lime Kiln is authorized to fire residual fuel oil with a maximum fuel sulfur content of 2.35% by weight as the primary fuel. On-specification used oil meeting the requirements in Appendix G of this permit may be blended with the residual oil and fired at a rate of no more than 10% of the fuel consumed. Natural gas is authorized as a startup and alternate fuel. The maximum heat input rate is 140 MMBtu per hour when firing a maximum of 933 gallons per hour of residual oil with a heating value of 150,000 Btu per gallon. No more than 8,173,000 gallons of oil shall be fired during any consecutive 12 months. [Application No. 1070005-038-AC; Rule 62-210.200 (PTE), F.A.C.]

EMISSIONS AND PERFORMANCE STANDARDS

7. CO Standard: As determined by EPA Method 10, CO emissions shall not exceed 69.0 ppmvd at 10% O_2 and 16.3 lb/hour based on the average of three test runs. [Rule 62-212.400 (BACT), F.A.C.]

8. NOx Standard: As determined by EPA Method 7E, NO_X emissions shall not exceed 140.0 ppmvd at 10% O_2 and 54.2 lb/hour based on the average of three test runs. [Rule 62-212.400 (BACT), F.A.C.]

9. PM Standard: As determined by EPA Method 5, PM emissions from the No. 4 Lime Kiln shall not exceed 0.55 lb per ton of actual material processed and 22.9 lb/hour based on the average of three test runs. *{Permitting Note: The venturi scrubber causes a wet plume, which interferes with the determination of opacity. The scrubber monitoring provisions will be used to ensure proper operation of the venturi scrubber.}* [Rule 62-212.400 (BACT), F.A.C.]

10. SO_2 Standard: As determined by EPA Method 8, SO_2 emissions shall not exceed 16.9 ppmvd at 10% O_2 and 9.1 lb/hour based on the average of three test runs. [Rule 62-212.400(12), F.A.C.]

11. TRS Standard: As determined by the existing CEMS, TRS emissions shall not exceed 25.1 tons per year based on a 12-month rolling CEMS total. [Rule 62-212.400(12), F.A.C.]

12. VOC Standard: As determined by EPA Method 25A, VOC emissions from the lime kiln shall not exceed 70.0 ppmvd at 10% O_2 and 9.4 lb/hour (total hydrocarbons determined as methane) based on the average of three test runs. [Rule 62-212.400 (BACT), F.A.C.]

COMPLIANCE MONITORING AND TESTING

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

14. 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.]

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

Method	Description of Method and Comments
1-4	Traverse Points, Velocity and Flow Rate, Gas Analysis, and Moisture Content
5	Determination of Particulate Matter from Stationary Sources
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources {Note: The method shall be based on a continuous sampling train.}
19	Determination of Sulfur Dioxide Removal Efficiency and Particulate Matter, Sulfur Dioxide, and Nitrogen Oxides Emission Rates (Optional F-factor method may be used to determine flow rate and gas analysis to calculate mass emissions in lieu of Methods 1-4.)
25A	Method for Determining Gaseous Organic Concentrations (Flame Ionization)

Tests shall also be conducted in accordance with the requirements specified in Appendix D (Standard Testing Requirements) of this permit. The above methods are described in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C. [Rules 62-204.800 and 62-297.100, F.A.C.; 40 CFR 60, Appendix A]

16. Initial Compliance Tests: The No. 4 Lime Kiln shall be tested to demonstrate initial compliance with the emissions standards specified for CO, NO_X, PM, SO_2, and VOC. The initial tests shall be conducted within 60 days after completing the kiln modification and achieving permitted capacity, but not later than 180 days after initial operation of the unit. [Rules 62-297.310(7)(a)1 and 62-212.400 (BACT), F.A.C.]

17. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), the No. 4 Lime Kiln shall be tested to demonstrate compliance with the emissions standards for CO, NO_X, PM, SO_2, and VOC. If consecutive annual tests for CO or VOC emissions show compliance at 50% of the standard or less, the test frequency for that pollutant is reduced to testing prior to renewal of the operation permit.. Annual testing shall resume for any subsequent failure to demonstrate compliance at renewal. [Rules 62-297.310(7)(a)4 and 62-212.400 (BACT), F.A.C.]

18. Tests Prior to Renewal: Within the 12-month period prior to expiration of the operation permit, the No. 4 Lime Kiln shall be tested to demonstrate compliance with the emission standards for CO, NO_X, PM, SO_2, and VOC. [Rules 62-297.310(7)(a)3 and 62-212.400 (BACT), F.A.C.]

19. Scrubber Monitoring: The permittee shall install, operate, and maintain equipment to continuously monitor and record the venturi scrubber pressure drop and flow rate. In accordance with the monitoring requirements specified in NESHAP Subpart MM, minimum operating levels shall be determined for these parameters; however, the operating levels shall be selected to ensure compliance with the BACT standard specified in this permit. If monitors show operation below the minimum operating levels, the permittee shall take appropriate corrective actions to regain proper operation of the control system. [Rules 62-4.070(3) and 62-212.400 (BACT), F.A.C.]

20. Fuel Monitoring: The permittee shall install equipment to continuously monitor the flow rates of natural gas and DNCGs to the No. 5 Power Boiler. This may consist of fuel flow meters with integrators to monitor each flow rate. [Rules 62-4.070(3) and 62-212.400(12), F.A.C.]

RECORDS AND REPORTS

21. Scrubber Records: The permittee shall continuously monitor and record the venturi scrubber pressure drop and flow rate in accordance with the monitoring requirements specified in NESHAP Subpart MM. The permittee shall document and record corrective actions taken to regain proper operation of the control system if operation falls below the minimum operating levels. [Rules 62-4.070(3) and 62-212.400 (BACT), F.A.C.]

22. Kiln Process Rate: The permittee shall monitor and record the total lime mud input to the No. 4 Lime Kiln on an hourly basis and record the daily average in tons per hour. [Rule 62-4.070(3), F.A.C.]

23. Fuel Records: On a monthly basis, the permittee shall document the amount of oil fired during each calendar month and the 12-month rolling total. [Rule 62-4.070(3), F.A.C.]

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 lime kiln processing rate, the fuel firing rate, the venturi scrubber pressure differential, and the venturi scrubber flow rate. [Rule 62-297.310(8), F.A.C.]

D. No. 4 Recovery Boiler

This subsection of the permit addresses the following emissions unit.

ID	Emission Unit Description
018	**No. 4 Recovery Boiler**: This unit fires black liquor solids (BLS) as the primary fuel to facilitate the recovery of the cooking liquor. Residual fuel oil is fired as a startup and supplemental fuel. The maximum steam production rate is 789,000 lb/hour (24-hour average) for steam conditions of 850° F to 900° F at 1250 psi. Particulate matter emissions are controlled by an electrostatic precipitator (ESP) with automatic voltage control, 2-chambers, and 6 electric fields per chamber. Total reduced sulfur emissions are reduced by the low-odor design. NO_X emissions are controlled by a four-level overfire air system. CO and VOC emissions are controlled by good combustion design and operating practices. CO, NO_X, SO_2, TRS, and opacity are continuously monitored and recorded. At permitted capacity, the exhaust gas flow rate is 294,000 dscfm at 8% oxygen with an exit temperature of 400° F. Exhaust gases exit a stack that is 12 feet in diameter and 230 feet tall.

{Permitting Note: In accordance with Rule 62-212.400 (PSD), F.A.C., the above emission unit is subject to BACT determinations for CO, NO_X, PM, and VOC emissions, which are presented in Appendix E of this permit.}

EXISTING APPLICABLE REGULATIONS

1. State Rule for Kraft Pulp Mills: The No. 4 Recovery Boiler is subject to the applicable requirements for existing units in Rule 62-296.404, F.A.C. These standards are specified in the Title V air operation permit.
2. NSPS Subpart BB: The No. 4 Recovery Boiler is subject to the applicable requirements specified in NESHAP Subpart BB of 40 CFR 63 for recovery combustion sources at Kraft pulp mills. These standards are specified in the Title V air operation permit.
3. NESHAP Subpart MM: The No. 4 Recovery Boiler is subject to the applicable requirements specified in NESHAP Subpart MM of 40 CFR 63 for recovery combustion sources at Kraft pulp mills. These standards are specified in the Title V air operation permit.
4. PSD Permits: Unless otherwise specified by condition in this permit, the No. 4 Recovery Boiler remains subject to the applicable requirements of Permit Nos. PSD-FL-171 and PSD-FL-226.

MODIFICATIONS AND CAPACITIES

5. No. 4 Recovery Boiler Modifications: The permittee is authorized to perform the following modifications to the No. 4 Recovery Boiler in accordance with the following preliminary schedule: modify the combustion air system; add a fourth level of overfire air (quaternary air); and replace tubes in the superheater, economizer, and walls of the recovery boiler. These changes will not increase the existing permitted capacity of the recovery boiler or the pulp mill. The preliminary schedule is to begin construction in May of 2007. [Application No. 1010005-038-AC; Rules 62-212.300 and 62-212.400 (PSD), F.A.C.]
6. Capacities, Fuels and Restrictions: The No. 4 Recovery Boiler fires BLS as the primary fuel for the recovery process as well as the following fuels: natural gas as a startup and supplemental fuel; residual fuel oil with a maximum sulfur content of 2.35% by weight; and limited amounts of on-specification used oil meeting the requirements in Appendix G of this permit. The permitted capacity is 210,000 lb/hour of BLS based on a 24-hour average. The maximum consumption of oil (residual oil and on-specification used oil) shall not exceed 7,860,640 gallons during any consecutive 12-months. On-specification used oil shall be blended with residual oil and shall not exceed 10% of the oil consumed. Hours of operation are not restricted (8760 hours/year). *{Permitting Note: The maximum heat input from firing BLS is 1345*

MMBtu/hour based on the permitted capacity and a heating value of 6410 Btu/lb of BLS. The oil firing restriction maintains an annual capacity factor of less than 10% for fossil fuel firing.} [Application No. 1070005-038-AC; Rules 62-210.200 (PTE) and 62-212.400 (PSD), F.A.C.]

7. Fuel Monitoring: The permittee shall install equipment to continuously monitor the flow rates of all fuels for the No. 4 Recovery Boiler. This may consist of fuel flow meters with integrators to monitor each flow rate. [Rules 62-4.070(3) and 62-212.400 (PSD), F.A.C.]

8. CEMS: To demonstrate compliance with the emissions standards for the No. 4 Recovery Boiler, the permittee shall properly install, calibrate, operate and maintain continuous emissions monitoring systems (CEMS) to measure and record CO and NO_X emissions in the terms of the applicable standard. The systems shall include continuous monitors to determine the flue gas oxygen 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 locate the CEMS by following the procedures contained in the applicable performance specification of 40 CFR Part 60, Appendix B. Within 240 calendar days of completing construction of the fourth level of overfire air, the permittee shall install and certify the required CEMS in accordance with the applicable performance specifications identified in Appendix F (Standard Continuous Monitoring Requirements) of this permit. *{Permitting Note: This unit has existing continuous monitors for determining opacity, SO_2 and TRS emissions.}* [Rules 62-4.070(3) and 62-212.400 (PSD), F.A.C.]

EMISSIONS AND PERFORMANCE STANDARDS

9. CO Standards:

   a. After completing installation of the four-level overfire air system, CO emissions shall not exceed 800.0 ppmvd @ 8% O_2 and 1025.4 lb/hour as determined by EPA Method 10 stack testing. *{Permitting Note: Once compliance with this standard is demonstrated and the CO CEMS is certified, this standard becomes obsolete.}*

   b. Once the CO CEMS is certified, compliance shall be determined by data collected from the required CEMS. For the initial 180 calendar days after certifying the CEMS, CO emissions shall not exceed 800.0 ppmvd @ 8% O_2 and 1025.4 lb/hour based on a 30-day rolling CEMS average, excluding periods of startup and shutdown. Thereafter, CO emissions shall not exceed 400.0 ppmvd @ 8% O_2 and 512.7 lb/hour based on a 30-day rolling CEMS average, excluding periods of startup and shutdown. [Rule 62-212.400 (BACT), F.A.C.]

10. NOx Standards:

    a. After completing installation of the four-level overfire air system, NO_X emissions shall not exceed 80.0 ppmvd @ 8% O_2 and 168.5 lb/hour as determined by EPA Method 10 stack testing. *{Permitting Note: Once compliance with this standard is demonstrated and the NO_X CEMS is certified, this standard becomes obsolete.}*

    b. As determined by data collected from the required CEMS, NO_X emissions shall not exceed 80.0 ppmvd @ 8% O_2 and 168.5 lb/hour based on a 30-day rolling CEMS average, excluding periods of startup and shutdown. [Rule 62-212.400 (BACT), F.A.C.]

11. Opacity Standard: Once the ESP in placed in service during startup of the recovery boiler, visible emissions shall not exceed 20% opacity based on a 6-minute average as determined by the existing COMS and EPA Method 9. [Rule 62-212.400 (BACT), F.A.C.]

12. PM Standard: As determined by EPA Method 5 or 29, PM emissions shall not exceed 0.030 grains per dscf @ 8% O_2 and 75.6 lb/hour based on the average of three test runs. [Rule 62-212.400 (BACT), F.A.C.]

13. SO2 Standard: As determined by data collected from the existing CEMS, SO_2 emissions shall not exceed 153.9 tons per year based on a 12-month rolling CEMS total. [Rule 62-212.400(12), F.A.C.]

14. TRS Standard: As determined by data collected from the existing CEMS, TRS emissions shall not exceed 34.2 tons per year based on a 12-month rolling CEMS total. [Rule 62-212.400(12), F.A.C.]

15. VOC Standard: As determined by EPA Method 25A, VOC emissions shall not exceed 0.20 lb/ton of BLS and 21.0 lb/hour (THC determined as methane) based on the average of three test runs. [Rule 62-212.400 (BACT), F.A.C.]

16. ESP Operation: The permittee shall operate and maintain the ESP to minimize PM emissions. The permittee may conduct additional stack tests with fields removed from service to determine compliance with the PM and opacity standards for these periods. During such tests, the permittee shall continuously monitor and record the parameters necessary to determine the secondary power input to the ESP. If these tests demonstrate compliance, the permittee is authorized to operate the ESP under the operating conditions of the tests when conducting repairs or maintenance on the ESP. [Rules 62-4.070(3) and 62-212.400 (BACT), F.A.C.]

COMPLIANCE MONITORING AND TESTING

17. Compliance by CEMS: Compliance with the opacity, SO_2, and TRS standards shall be demonstrated with data collected from the existing COMS and 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 comply with the conditions of Appendix F (Standard Continuous Monitoring Requirements) of this permit as the compliance method for the corresponding emissions standards. [Rules 62-4.070(3) and 62-212.400 (BACT), F.A.C.]

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

19. 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.]

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

EPA Method	Description of Method and Comments
1 - 4	Methods for Determining Traverse Points, Velocity, Flow Rate, Gas Analysis, and Moisture Content These methods shall be performed as necessary to support other methods.
5	Method for Determining Particulate Matter Emissions
7E	Method for Determining NOx Emissions (Instrumental)
9	Method for Determining Opacity Observations
10	Method for Determining Carbon Monoxide Emissions (Instrumental) The method shall be based on a continuous sampling train.
19	Methods for Determining NO_X, PM, and SO_2 Mass Emission Rates
25A	Method for Determining Gaseous Organic Concentrations (Flame Ionization)
29	Method for Determining Metals Emissions from Stationary Sources

The above methods are specified in Appendix A of 40 CFR 60 and are adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used unless prior written approval is received from the

Department. [Rules 62-4.070(3), 62-204.800(8) and 62-212.400 (BACT), F.A.C.; 40 CFR 60, Appendix A]

21. 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 for CO, NO_X, PM and VOC.

    a. *Initial Tests*: Initial compliance tests shall be conducted within 60 calendar days of installing the fourth level of overfire air and achieving permitted capacity, but no later than 180 calendar days after initial startup. For the initial CO and NO_X tests prior to certification of the CEMS, the permittee shall demonstrate compliance with at least three hours of data, but no more than nine hours of data. [Rules 62-212.400 (BACT) and 62-297.310(7), F.A.C.]

    b. *Subsequent Tests*: During each federal fiscal year (October 1st to September 30th), compliance tests shall be conducted to determine PM emissions. Because VOC emissions are expected to be low and the CO CEMS will ensure efficient combustion, subsequent tests shall be conducted prior to renewal of the operation permit or when the Department requests a special test pursuant to Rule 62-297.310(7)(b), F.A.C.

    c. *Test Fuel*: Compliance tests shall be conducted when firing BLS at permitted capacity. [Rules 62-4.070(3), 62-212.400 (BACT) and 62-297.310, F.A.C.]

    d. *Operational Data for Tests*: For each test run, the permittee shall monitor and record the following information: fuel feed rate; the secondary power input to the ESP; the flue gas oxygen content (%); CO, NO_X, SO_2 and TRS CEMS data; and opacity COMS data. [Rules 62-297.310 and 62-4.070(3), F.A.C.]

RECORDS AND REPORTS

22. Stack Test Reports: The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Compliance Authority on the results of each such test. The required test report shall be filed with the Compliance Authority as soon as practical but no later than 45 days after the last sampling run of each test is completed. The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the Compliance Authority 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 information specified in Rule 62-297.310(8), F.A.C. The stack test shall also report all operational data collected during each test run. [Rule 62-297.310(8), F.A.C.]

23. Semiannual Monitoring Reports: The permittee shall submit a written report to the Compliance Authority summarizing the following for each calendar quarter: CO, NO_X, SO_2, and TRS emissions; opacity; CEMS monitor availability; gallons of oil 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. [Rule 62-4.070(3), F.A.C.]

E. No. 4 Multiple Effect Evaporator Set

This subsection of the permit addresses the following emissions unit.

ID	Emission Unit Description
xxx	Noncondensable Gas System including the No. 4 Multiple Effect Evaporator (MEE) Set

EXISTING APPLICABLE REGULATIONS

1. State Rule for Kraft Pulp Mills: This emissions unit is subject to the applicable requirements for existing units in Rule 62-296.404, F.A.C. These standards are specified in the Title V air operation permit.

2. NSPS Subpart BB: This emissions unit is subject to the applicable requirements specified in NESHAP Subpart BB of 40 CFR 63 for recovery combustion sources at Kraft pulp mills. These standards are specified in the Title V air operation permit.

MODIFICATIONS AND CAPACITIES

3. No. 4 MEE Set: The permittee is authorized to install a new crystallizer and associated storage/flash tank as a modification to the existing multiple effect evaporator (MEE) set with two associated concentrators (EU-032). The purpose is to increase the temperature and flash-off moisture from the black liquor, which will increase the solids content of the BLS from 65% to approximately 75%. The BLS fired in the existing No. 4 Recovery Boiler will contain less moisture. Emissions from the crystallizer and associated storage/flash tank shall be directed back to the MEE set and collected as part of the existing noncondensable gas (NCG) collection system. The preliminary schedule is to begin construction in May of 2007 and startup the new equipment by May of 2008. [Application No. 1010005-038-AC; Rules 62-212.300 and 62-212.400 (PSD), F.A.C.]

CONTENTS

CITATION FORMATS

The following examples illustrate the format used in the permit to identify applicable permitting actions and regulations.

REFERENCES TO PREVIOUS PERMITTING ACTIONS

Old Permit Numbers

Example: Permit No. AC50-123456 or Air 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

"001"identifies the specific permit project

"AC" identifies the permit as an air construction permit

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

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

"AV" identifies the permit as a Title V Major Source Air Operation Permit

PSD Permit Numbers

Example: Permit No. PSD-FL-317

Where: "PSD" means issued pursuant to 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

RULE CITATION FORMATS

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

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 and 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;
    b. Determination of Prevention of Significant Deterioration; and
    c. Compliance with New Source Performance Standards.

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 to all emissions units and activities at the facility.

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

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 conditions apply to all emissions units and activities 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 [Rule 62-297.310(4), F.A.C.]
   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. *Calibration of Sampling Equipment.* Calibration of the sampling train equipment shall be conducted in accordance

with the schedule shown in Table 297.310-1.

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

5. Determination of Process Variables [Rule 62-297.310(5), F.A.C.]

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.

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

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.

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

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.

RECORDS AND REPORTS

8. <u>Test Reports</u>:
   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.]

FINAL BACT DETERMINATIONS AND EMISSIONS SUMMARY

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 oil and natural gas.

This permit authorizes the following major modifications: permanent shutdown of the No. 4 Power Boiler (EU-014); conversion of the No. 5 Power Boiler (EU-015) to natural gas; replacement of the hot-end shell and coolers for the No. 4 Lime Kiln (EU-017); extensive tube replacement and the addition of a fourth level of over-fire air for the No. 4 Recovery Boiler (EU-018); and, the addition of a crystallizer with associated storage/flash tank and modifications to the two existing concentrators associated with the No. 4 multiple effect evaporator set (EU-032).

The permittee conducted a PSD netting analysis based on contemporaneous emissions increases and decreases to avoid PSD preconstruction review for sulfur dioxide (SO_2), sulfuric acid mist (SAM), and total reduced sulfur (TRS). The project is subject to PSD preconstruction review for carbon monoxide (CO), nitrogen oxides (NO_X), particulate matter (PM), and volatile organic compounds (VOC). For this permit, the Department determined the Best Available Control Technology (BACT) for the following units: the No. 5 Power Boiler (CO and VOC); the No. 4 Lime Kiln (CO, NO_X, PM, and VOC); and the No. 4 Recovery Boiler (CO, NO_X, PM, and VOC). The No. 4 Combination Boiler is currently under PSD preconstruction review in Project No. 1070005-045-AC for CO, NO_X, PM, and VOC. Throughout this appendix particulate matter emissions are referred to as PM emissions, which serve as a surrogate for regulating $PM_{2.5}$ and PM_{10} emissions.

FINAL BACT DETERMINATIONS

For this project, the applicant conducted a PSD netting analysis that included all contemporaneous emissions increases and decreases. In accordance with Rule 62-212.400 (PSD), F.A.C., the Department establishes the following standards as BACT for CO, NO_X, PM, and VOC emissions.

Pollutant	BACT Standards	Control Technology	Monitoring
No. 5 Power Boiler			
CO [a]	0.185 lb/MMBtu and 105.2 lb/hour	good combustion design and practices for firing natural gas	annual tests
VOC [a]	CO is surrogate standard		no tests required
No. 4 Lime Kiln			
CO [b]	69.0 ppmvd at 10% O_2 and 16.3 lb/hour	good combustion design and practices	annual tests
NO_X	140.0 ppmvd at 10% O_2 and 54.2 lb/hour	good combustion design and practices	annual tests
Opacity	Due to wet plume, scrubber pressure differential and flow rate are continuously monitored.		
PM	0.55 lb/ton processed and 22.9 lb/hour	cyclones and wet venturi scrubber	annual tests
VOC [b]	70.0 ppmvd at 10% O_2 and 9.4 lb/hour	good combustion design and practices	annual tests
No. 4 Recovery Boiler			
CO [c]	400.0 ppmvd @ 8% O_2 and 512.7 lb/hour	good combustion design and practices	CEMS
NO_X [c]	80.0 ppmvd @ 8% O_2 and 168.5 lb/hour	four-level over-fire air system	CEMS
Opacity [d]	20%, 6-minute averages	electrostatic precipitator	COMS
PM	0.030 grains/dscf @ 8% O_2 and 75.6 lb/hour	electrostatic precipitator	annual tests
VOC [e]	0.20 lb/ton of BLS and 21.0 lb/hour	good combustion design and practices	initial/renewal tests

a. For the No. 5 Power Boiler, only CO and VOC emissions will increase after converting to natural gas. All other pollutants will decrease.

b. For the No. 4 Lime Kiln, the testing frequency may be reduced to testing prior to renewal of the operating permit if consecutive tests show emissions below 50% of the emissions standard. CO and VOC emissions are expected to be low due to relatively high kiln temperature and a long residence time. EPA Method 25A used to determine total hydrocarbons measured as methane.

c. For the No. 4 Recovery Boiler, the CO and NO_X standards are based on a 30-day rolling CEMS average excluding emissions data collected during startup and shutdown. For the first 180 days after certifying the CEMS, CO emissions shall not exceed 800.0 ppmvd @ 8% O_2 and 1025.4 lb/hour based on a 30-day rolling CEMS average, excluding data collected during startup and shutdown. The purpose of this interim standard is to provide sufficient time to develop good combustion practices for the four-level overfire air system.

d. For the No. 4 Recovery Boiler, the opacity standard applies once the electrostatic precipitator is placed in service during startup.

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

OTHER EMISSIONS STANDARDS

This permit establishes the following additional standards that allow the project to avoid PSD preconstruction review for NO_X, SAM, SO_2, and TRS.

Pollutant	Standards	Monitoring
No. 5 Power Boiler		
NO_X	0.125 lb/MMBtu and 71.1 lb/hour	annual tests
No. 4 Lime Kiln		
SO_2	16.9 ppmvd @ 10% O_2 and 9.1 lb/hour	annual tests
TRS	25.1 tons per year, 12-month rolling CEMS total	CEMS
No. 4 Recovery Boiler		
SO_2	153.9 tons per year, 12-month rolling CEMS total	CEMS
TRS	34.2 tons per year, 12-month rolling CEMS total	CEMS

EMISSIONS SUMMARY

Pollutant	Annual Potential Emissions, tons/year		
	No. 5 Power Boiler[a]	No. 4 Lime Kiln	No. 4 Recovery Boiler
CO	460.8	71.4	2245.6
NO_X	311.4	237.4	738.0
PM	18.9	100.3	331.1
SO_2	1.5	39.9	153.9
TRS	Negligible	25.1 [b]	34.2
VOC	13.7	41.2	92.0

a. Emissions from the No. 5 Power Boiler are based on firing 100% natural gas.

b. Based on current TRS standard in Title V permit.

STANDARD CONTINUOUS MONITORING REQUIREMENTS

The No. 4 Recovery Boiler (EU-018) is subject to the following requirements for the new continuous emissions monitoring systems (CEMS) required for CO and NO_X emissions. The unit also has existing CEMS for SO_2 and TRS emissions and a continuous opacity monitoring systems (COMS).

CEMS OPERATION PLAN

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

MONITORS, PERFORMANCE SPECIFICATIONS AND QUALITY ASSURANCE

2. 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.]

3. 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 monitor or install a CO_2 monitor and use an appropriate F-Factor computational approach. [Rules 62-212.400 (BACT) and 62-4.070(3), F.A.C.]

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

5. 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 stack exhaust flow rate. *{Permitting Note: The CEMS Operation Plan will contain additional details and procedures for CEMS installation.}* [Rules 62-212.400 (BACT) and 62-4.070(3), F.A.C.]

6. 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.]

7. 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

8. 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 (BACT) and 62-4.070(3), F.A.C.]

9. 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.]

10. 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.]

11. 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.]

12. Calculation Approaches: The permittee shall implement the calculation approach specified by this permit for each CEMS, as follows:

    a. *Daily Averages*: A daily average shall be calculated and recorded for each operating day as the arithmetic average of all valid hourly averages occurring from midnight to midnight.

    b. *Rolling 30-day Average*. Compliance with the 30-day rolling average 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).

    c. *Rolling 12*-month Average:

    d. *Rolling 12*-month Totals:

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

13. 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

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

EXCESS EMISSIONS

15. 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 (Definitions), F.A.C.]

16. 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), F.A.C.]

17. 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. 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, excess emissions data collected during periods of startup and shutdown may be excluded from compliance calculations as allowed by the permit standards.

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

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

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

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

{Permitting Note: 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 (BACT) and 62-210.700(4), F.A.C.]

18. 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.

CALCULATING AND REPORTING ANNUAL EMISSIONS

19. 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.

20. 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.

21. Emissions Calculation: Annual emissions shall be calculated as the sum of all valid emissions occurring during the year.

22. 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 (BACT) and 62-4.070(3), F.A.C.]

APPENDIX G. 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).

APPENDIX G. ON-SPECIFICATION USED OIL REQUIREMENTS

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]