REVISED
TECHNICAL EVALUATION
AND
PRELIMINARY DETERMINATION

PROJECT

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

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

COUNTY

Putnam County, Florida

APPLICANT

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

PERMITTING AUTHORITY

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

August 15, 2008

1. GENERAL PROJECT INFORMATION

Application for PSD Air Construction Permit

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

Facility Description and Location

Georgia-Pacific operates an existing Kraft paper and pulp mill (SIC Nos. 2611 and 2621) in Putnam County, north of County Road 216 and west of U.S. Highway 17 in Palatka, Florida. The UTM map coordinates are: Zone 17, 434.0 km East, and 3283.4 km North. In the Kraft process, the digesting liquor (white liquor) is a solution of sodium hydroxide and sodium sulfide that is mixed with wood chips and cooked under pressure. The spent liquor, known as weak black liquor, is concentrated and sodium sulfate is added to make up for chemical losses. The black liquor solids (BLS) are burned in the recovery furnace to produce a smelt of sodium carbonate and sodium sulfide. The smelt is dissolved in water to form green liquor to which quicklime (calcium oxide) is added to convert the sodium carbonate back to sodium hydroxide, which reconstitutes the cooking liquor. The spent lime cake (calcium carbonate) is recalcined in a rotary lime kiln to produce quicklime, which is used to convert the green liquor to cooking liquor. Steam and energy needs are met by the combination, power and recovery boilers, which burn a variety of fuels including carbonaceous, BLS, fuel oil and natural gas.

Facility Regulatory Categories

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

Regulated Pollutants

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

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

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

Project Description

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

and supplemental fuel. Particulate matter emissions are currently controlled with a multiple cyclone (multiclone) pre-cleaner followed in series by an electrostatic precipitator (ESP).

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

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

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

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

Reviewing and Processing Schedule

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

06/01/07: Receipt of additional information;

06/29/07: Request for additional information;

11/13/07: Receipt of additional information;

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

11/29/07: Receipt of additional information;

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

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

01/11/08: Receipt of additional information;

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

04/14/08: The applicant waived the 90-day time clock to conduct additional emissions testing and provide results;

05/09/08: The Department issued the initial draft permit package;

05/24/08: The applicant published the Public Notice in the Palatka Daily News;

06/02/08: The Department received proof of publication;

06/20/08: The Department received substantial comments from the applicant concerning the draft permit;

07/17/08: The Department held a teleconference to discuss the applicant's comments;

07/24/08: The Department held another teleconference to discuss the applicant's comments; and

08/06/08: The Department received a letter from the applicant requesting a revised draft permit.

After publishing the Public Notice, the applicant provided the following comments on the draft permit package.

1. *Comment*: In the "Project Description" in Section I of the permit, the applicant requested removal of the discussion concerning combustion zone temperature monitoring, which is not required by NSPS Subpart S. The applicant also notes that DNCG may originate from the oxygen delignification (OD) system, the post-OD washer and the bleach plant washer in addition to the brown stock washer and associated pressure knotters and screens.

   Response: The discussion of the combustion zone temperature monitoring refers to the requirements of Rule 62-296.404, F.A.C. and will not be changed. The Department will revise the project description to clarify that DNCG may also be generated by the oxygen delignification (OD) system, the post-OD washer and the bleach plant washer.

2. *Comment*: In Condition 18, the applicant requests that the permit allow 18 months instead of 12 months to install an SNCR system if necessary. This would allow sufficient time for the final design, engineering, installation, shakedown and testing of the equipment.

   Response: This is acceptable and will be revised accordingly.

3. *Comment*: The applicant contacted the equipment vendor for the ESP modifications to secure a guarantee for the Department's proposed PM standard of 0.030 lb/MMBtu. The vendor indicated that it would be necessary to install a 4th field on each ESP to guarantee this level of emissions. Initially, the capital costs for the applicant's proposed ESP modifications to achieve a PM standard of 0.040 lb/MMBtu were estimated as $1.4 to $2.35 million. The additional capital costs to add a 4th field to each ESP were estimated to be an additional $5 million. The applicant indicates that these costs are unreasonable and the project would be abandoned. The applicant requests that the PM standard be established as 0.040 lb/MMBtu with quarterly stack tests to demonstrate compliance. In addition, COMS would be added to each exhaust stack to verify compliance with the opacity standard. The applicant is willing to modify the permit to reduce the PM emissions standards (no lower than 0.030 lb/MMBtu) based on the results of the quarterly stack tests and a margin for compliance.

   Response: The Department believes that the proposed ESP modifications (without the 4th field) will result in emissions levels that will comply with the initially proposed draft standard of 0.030 lb/MMBtu. Particularly, the mechanical dust collectors should be able to remove much of the ash generated from fuel combustion and greatly reduce the ash loading to each ESP. However, as the applicant's vendor indicated, the aspect ratio (length/height) of each ESP is only 0.82. Generally, an aspect ratio of more than 1.0 is desirable to prevent re-entrainment of ash when the plates are rapped to remove collected dust. Therefore, the Department agrees to revise the permit to include: a PM emissions standard of 0.040 lb/MMBtu; initial quarterly stack testing; COMS on each stack; and a requirement to modify the permit for a reduced PM standard based on the quarterly compliant test results. For details, see the additional discussion in this Technical Evaluation and Preliminary Determination under "BACT Review for PM/PM_{10}/$PM_{2.5}$ Emissions".

The Department considers these comments to be substantial and will issue a revised draft permit package, which requires the applicant to publish a new Public Notice with a 30-day comment period.

4. RULE APPLICABILITY

State Regulations

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

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

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

Federal Regulations

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

<u>NSPS Applicability</u>

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

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

NESHAP Applicability

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

PSD Applicability

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

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

PSD Applicability for the Project

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

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

Pollutant	Emissions in Tons per Year [2]					Subject to PSD?
	Baseline	Future Potential	Contemporaneous Emission Changes	Net Emissions Change	PSD Significant Emission Rates	
CO	2094.7	4024.7	19.6	1949.5	100	Yes
NO_X	1504.5	2009.4	- 3.4	501.5	40	Yes
PM	530.0	659.7	- 6.7	122.9	25	Yes
PM_{10}	433.5	534.6	- 4.3	96.8	15	Yes
SAM	183.5	20.4	0.3	- 162.8	7	No
SO_2	4179.2	290.9	- 362.0	- 4250.3	40	No
TRS	26.0	83.7	- 53.5	4.2	10	No
VOC	329.2	812.8	- 58.10	425.5	40	Yes
Pb	0.260	0.40	- 0.005	0.135	0.6	No
Hg	0.0059	0.0095	-0.000081	0.0034	0.1	No
Fl	0.449	0.000	- 0.027	- 0.475	3	No

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

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

General Requirements for BACT Reviews

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

(a) An emission limitation, including a visible emissions standard, based on the maximum degree of reduction of each pollutant emitted, which the Department, on a case by case basis, taking into account:

1. *Energy, environmental and economic impacts, and other costs;*
2. *All scientific, engineering, and technical material and other information available to the Department; and*
3. *The emission limiting standards or BACT determinations of Florida and any other state; determines is achievable through application of production processes and available methods, systems and techniques (including fuel cleaning or treatment or innovative fuel combustion techniques) for control of each such pollutant.*

(b) If the Department determines that technological or economic limitations on the application of measurement methodology to a particular part of an emissions unit or facility would make the imposition of an emission standard infeasible, a design, equipment, work practice, operational standard or combination thereof, may be prescribed instead to satisfy the requirement for the application of BACT. Such standard shall, to the degree

possible, set forth the emissions reductions achievable by implementation of such design, equipment, work practice or operation.

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

(d) In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR Parts 60, 61, and 63.

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

General Requirements for the PSD Air Quality Analysis

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

5. BACT REVIEW FOR THE NO. 4 COMBINATION BOILER

Discussion of Emission Changes

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

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

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

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

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

Discussion of PM Emissions

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

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

Available Technologies for Controlling PM Emissions

The main abatement options for controlling PM emissions include:

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

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

Applicant's PM BACT Proposal

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

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

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

emissions and avoid overloading the ESP; and

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

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

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

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

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

Additional Discussion

As previously mentioned, the applicant provided substantial comments to the initial draft permit, which resulted in this revised draft permit package. Specifically, the applicant's equipment vendor for the ESP modifications would not guarantee the initially proposed PM standard of 0.030 lb/MMBtu unless a 4th field was installed on each ESP. The primary concern was a low aspect ratio (length/height) for each ESP of only 0.82. Generally, an aspect ratio of more than 1.0 is desirable to prevent re-entrainment of ash when the plates are rapped to remove collected dust. A low aspect ratio suggests that there may not be sufficient time for the re-entrained dust to settle out or be re-collected. The capital costs to add a 4th field to each ESP were estimated to be $5 million in addition to the costs of originally proposed ESP modifications estimated at $1.4 to $2.35 million. The applicant indicates that these costs are unreasonably high and the project would be abandoned. As an alternative, the applicant proposed:

- A revised PM standard of 0.040 lb/MMBtu;
- Initial quarterly stack tests to demonstrate compliance;
- Installation of a COMS in each stack to verify compliance with an opacity standard of, "When firing any authorized fuel or combination thereof, visible emissions shall not exceed 20% opacity based on a 6-minute average, except for one 6-minute period per hour that shall not exceed 27% opacity, as determined by COMS and/or EPA Method 9"; and
- Future modification of the permit to reduce the PM standard to no lower than 0.030 lb/MMBtu if warranted by the compliant stack test results with an adequate margin for compliance.

Department's PM BACT Review

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

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

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

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

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

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

η is the control efficiency

e is the logarithm base function and equal to ~2.718

w is the migration velocity

A is the collection area of the ESP

Q is the volumetric flow rate

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

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

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

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

Fuel	Uncontrolled	Mechanical Dust Collectors	ESP	Controlled

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

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

As shown in the table, this combination of controls can achieve very low PM emissions rates. The Department believes that the proposed ESP modifications (without a 4th field) will result in emissions levels that will comply with a PM standard of 0.030 lb/MMBtu. Particularly, the mechanical dust collectors should be able to remove much of the ash generated from fuel combustion and greatly reduce the ash loading to each ESP. However, as the applicant's vendor indicated, the aspect ratio (length/height) of each ESP is only 0.82, which is below the optimum specification (1.0 to 1.5) for preventing re-entrainment when rapping to remove dust from the collector plates. Therefore, the Department establishes the following draft PM BACT standards:

When firing any authorized fuel or combination thereof, PM emissions shall not exceed 0.040 lb/MMBtu and 22.6 lb/hour as determined by tests conducted in accordance with EPA Method 5 or 29. This BACT standard was based on the vendor guarantee for the proposed equipment modifications. The Department believes that such equipment modifications will achieve a much lower emissions rate. Therefore:

1. The permittee shall operate the PM control equipment to minimize emissions.
2. After completing the proposed work and as specified in this permit, the permittee shall conduct at least one stack test during each of the first four calendar quarters that demonstrate compliance with the PM BACT emissions standards.
3. The permittee shall submit reports summarizing the results for all quarterly stack tests. Each report shall also summarize operation of the PM controls.
4. The permittee shall submit an application to modify this permit by reducing the PM BACT emissions standard based on all quarterly stack tests demonstrating compliance with the current standard. The application shall detail the modifications made to the PM controls, provide the final design details, summarize the equipment capabilities and propose new PM BACT emissions standards. As deemed necessary by the Department, the permit will be modified to reduce the PM BACT emissions standards based on the application and all other relevant information available to the Department. The revised PM BACT emissions standards will be no lower than 0.030 lb/MMBtu and 16.9 lb/hour.

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

Based on ten opacity tests conducted from 1997 to 2007 using EPA Method 9, the average opacity is 5.1 %. Also for purposes of comparison, the NSPS Subpart Db standard is less than or equal to 20% opacity (6-minute average), except for one 6-minute period per hour of not more than 27%. With the proposed improvements, the modified boiler should readily meet a standard of 20% opacity. The applicant agrees to install COMS on each stack to demonstrate compliance. Therefore, the Department establishes the following draft opacity standard as PM BACT:

When firing any authorized fuel or combination thereof, visible emissions shall not exceed 20% opacity based

on a 6-minute average, except for one 6-minute period per hour that shall not exceed 27% opacity, as determined by COMS and/or EPA Method 9. This standard applies to each stack.

BACT Review for CO and VOC Emissions

Discussion of CO and VOC Emissions

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

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

Available Technologies for Controlling CO and VOC Emissions

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

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

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

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

Applicant's CO and VOC BACT Proposal

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

A catalytic oxidation system is a technically feasible add-on control option. Since the exhaust temperature

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

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

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

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

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

Department's BACT Review

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

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

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

b. This assumes uncontrolled CO + VOC emissions of 1277 tons/year and a control efficiency of 98% for thermal oxidation and 95% for catalytic oxidation.

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

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

As shown, the capital and operating costs for such systems are substantial. For the bark/wood-fired boiler, the costs would be near the higher end of the range because of the relatively low uncontrolled CO and VOC levels as well as the low flue gas temperatures leaving the ESP, which result in high natural gas costs. In addition, these estimates are based on full potential emissions. Costs will be much higher if the boiler does not operate full time, operates at partial loads for substantial periods or uncontrolled emissions are lower than expected. Therefore, the Department agrees that thermal and catalytic oxidation systems are not appropriate and are cost prohibitive for controlling CO and VOC emissions from the bark/wood-fired boiler. The Department accepts the applicant's proposal to install a new OFA system in the upper part of the No. 4 Combination Boiler to enhance complete combustion of all fuels and reduce CO and VOC emissions.

Draft CO BACT Determination

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

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

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

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

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

Draft VOC BACT Determination

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

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

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

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

Initial compliance shall be demonstrated by stack testing conducted while firing bark/wood at permitted capacity. Thereafter, compliance shall be assumed if the unit remains in compliance with the CO standards demonstrated by CEMS. Pursuant to Rule 62-297.310(7)(b), F.A.C., "When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it shall require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department."

BACT Review for NO_X Emissions

Discussion of NOx Emissions

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

- Thermal NO_X occurs in the high-temperature zone near the burner itself. The formation of thermal NO_X is affected by oxygen concentrations, peak flame temperatures and the time of exposure to peak temperatures. As these three components increase, thermal NO_X emissions will increase.
- Fuel NO_X is generated from nitrogen available in the fuel that is oxidized to NO_X.
- Prompt NO_X occurs in the flame itself and results from the early reactions of nitrogen molecules in the combustion air and hydrocarbon radicals in the fuel.

For wood-fired boilers, excess air is provided to ensure adequate oxygen for the combustion process, which results in moderately high oxygen levels (~ 7% oxygen). Operators attempt to maintain high furnace temperatures to combust all of the fuel. Wood-fired boilers are also designed with moderate furnace residence times to ensure complete combustion. These factors lead to the generation of significant amounts of thermal NO_X

emissions. Fuel NO_X emissions can be significant for bark/wood, but much less for residual oil and nearly negligible for natural gas. For combustion in conventional boilers and furnaces, prompt NO_X is generally insignificant when compared to the amounts of thermal and fuel NO_X emissions. Based on information in AP-42, average NO_X emissions from wood-fired, oil-fired, and natural gas-fired boilers are shown in the following table.

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

Available Technologies for the Control of NOx Emissions

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

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

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

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

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

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

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

Natural Gas Reburn: Reburn uses a set of natural gas burners installed above the primary combustion zone.

Natural gas is injected to form a fuel-rich, oxygen-deficient combustion zone above the main firing zone. Emissions of NO_X generated in the main firing zone travel upward into the reburn zone and are converted to N_2. The technology requires no catalyst, chemical reagents, or changes to any existing burners. Typical reburn systems also incorporate redesign of the combustion air system along with a water-cooled, pinhole grate to provide reduced excess air. For utility boilers, NO_X has been reduced by 35% to 50%.

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

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

Steam Injection: The injection of steam causes the stoichiometry of the mixture to be changed and reduces heat energy generated by combustion. These actions cause lower combustion temperatures, which in turn reduce the amount of thermal NO_X formed. Depending on the applications, potential reductions in NO_X emissions vary from 35% to 50%.

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

Applicant's NOx BACT Proposal

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

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

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

Review of Fuel Tech Hybrid SNCR/SCR System: The total installed capital cost is estimated to be $8,100,000. The catalyst is projected to have a 3-year operational life. The total annual operating cost is estimated to be $1,800,000. Based on the NO_X reduction potentials of the control system of 65% for bark/wood and 40% for fuel oil, the cost effectiveness is $6,457 per ton NO_X removed. This cost effectiveness is considered to be higher than the cost effectiveness that has been determined to be economically infeasible for existing industrial boilers in Florida. Also, there is significant uncertainty regarding the actual cost of the system, the performance of the system (i.e., catalyst life, maintenance, etc.) and the actual NO_X reduction that will be achieved, due to the lack of operating experience on industrial biomass-fired boilers. Therefore, the hybrid SNCR/SCR is rejected based on high costs.

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

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

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

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

Other Considerations

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

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

As shown in Attachment C of the application (including impacts from the No. 4 Lime Kiln and No. 4 Recovery Boiler), the maximum predicted NO_2 impacts for the proposed project are less than the AAQS and EPA Class I and II PSD increments. Additional NO_X controls for the No. 4 Combination Boiler would result in an

insignificant reduction of ambient impacts that are already only slightly above the EPA significance levels for both Class I and II areas.

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

Applicant's NO_X BACT Proposal

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

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

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

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

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

Department's NOx BACT Review

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

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

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

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

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

vendors.

- Although the Ecotube OFA and FGR systems are less capital intensive, the overall cost effectiveness of these systems appears to be more than $5000/ton of NO_X removed because of retrofit and control efficiency concerns.

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

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

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

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

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

- The proposed project will increase the maximum heat input rate from wood firing and improve overall combustion. This may increase furnace temperatures and NO_X emissions.
- Jansen believes that fuel NO_X contributes more to NO_X emissions than thermal NO_X for this emissions unit. The nitrogen content of the bark/wood at the Georgia-Pacific Palatka Mill was tested to be 0.91% by weight on a dry basis. This contrasts with an average value of 0.53% by weight on a dry basis from Jansen's data for wood samples. This means that the fuel NO_X contribution for boilers at Georgia-Pacific may be higher than for other wood-fired boilers.
- Based on the limited data, Jansen predicts a NO_X emissions rate of 0.26 lb/MMBtu for the upgraded boiler with OFA system.

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

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

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

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

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

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

CEMS Installations

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

4. AIR QUALITY IMPACT ANALYSIS

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

Overview of the Required Modeling Analyses

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

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

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

Preconstruction Ambient Monitoring Analysis

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

quality data) for any net increase of 100 tons per year or more of NO_2 or VOC emissions.

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

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

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

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

Source Impact Analysis

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

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

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

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

- The PSD increments and the AAQS for Class II areas.

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

PSD Class I Area Model

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

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

PSD Class II Area Model

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

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

Stack Height Considerations

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

Additional Impact Analysis

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

PSD Significant Pollutants for the Project

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

Preconstruction Ambient Monitoring Analysis

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

De Minimis Air Quality Levels				
Pollutant	**Averaging Time**	**Maximum Predicted Impact (µg/m^3)**	**De Minimis Concentration (µg/m^3)**	**Greater than De Minimis?**
CO	8-hr	79	575	No
NO_2	Annual	2	14	No
PM_{10}	24-hr	12	10	Yes

As shown above, CO and NO_2 are exempt from preconstruction monitoring because the predicted impacts are less than the de minimis levels. However, PM_{10} is not exempt from preconstruction ambient monitoring. In addition, the project results in PSD net emissions increases of 502 tons/year of NO_2 and 426 tons/year of VOC, which are each above the threshold of 100 tons/year that requires an ambient impact analysis including the gathering of ambient air quality data. Nevertheless, the Department maintains an extensive quality-assured ambient monitoring network throughout the state. The following table summarizes ambient data from 2003 to 2007 available for existing nearby monitoring locations.

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

The existing monitoring data show no violations of any ambient air quality standards. The Department determines that the data collected from these monitors is representative of the air quality in the vicinity of the project and may be used to satisfy the preconstruction monitoring requirements for CO, NO_2, ozone and PM_{10}. As necessary, the above ambient concentrations will be used as the ambient background concentrations for any required AAQS analysis.

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

Source Impact Analysis for PSD Class I Areas

Affected PSD Class I Areas

For PSD Class I areas within 200 kilometers of the facility, the table identifies each affected Class I area as well as the distance to the facility and the number of receptors used in the modeling analysis. Since each of these areas are greater than 50 kilometers from the proposed facility, long-range transport modeling was required for the PSD Class I impact assessment.

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

Meteorological Data for PSD Class I Analysis

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

Results of PSD Class I Significant Impact Analysis

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

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

As shown, the maximum predicted impacts are less than the corresponding significant impact levels for each pollutant. Therefore, a full impact analysis for the PSD Class I areas is not required.

Source Impact Analysis for PSD Class II Areas

Meteorological Data for PSD Class II Analysis

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

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

Results of the Significant Impact Analysis

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

Significant Impact Analysis for PSD Class II Areas (Vicinity of Facility)					
Pollutant	**Averaging Time**	**Maximum Predicted Impact (µg/m^3)**	**Significant Impact Level (µg/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	N/A
	1-hr	79	2,000	No	N/A
NO_2	Annual	2	1	Yes	1

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

Receptor Grids for Performing PSD Increments and AAQS Analyses

For the PSD Class II increment and AAQS analyses, receptor grids are normally based on the size of the significant impact area for each pollutant. As shown in the previous section, the predicted radius of significant impact for PM_{10} and NO_2 were 1 kilometer or less. However, the applicant placed over 2000 receptors along the restricted property line of the facility and out to 4 kilometers from the facility.

PSD Class II Increment Analysis

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

PSD Class II Increment Analysis				
Pollutant	**Averaging Time**	**Maximum Predicted Impacts (µg/m^3)**	**Allowable Increment (µg/m^3)**	**Greater than PSD Class II Allowable Increment?**
NO_2	Annual	3	25	No
PM_{10}	Annual	0	17	No
	24-hour	22	30	No

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

AAQS Analysis

For each pollutant subject to an AAQS analysis, the total impact on ambient air quality is obtained by adding an ambient background concentration to the maximum predicted concentration from modeled sources. The ambient background concentration accounts for all sources that are not explicitly modeled. The following table summarizes the results of the AAQS analysis for NO_2 and PM_{10}.

AAQS Analysis						
Pollutant	**Averaging Time**	**Modeled Sources (µg/m^3)**	**Ambient Background Concentration (µg/m^3)**	**Total Impact (µg/m^3)**	**AAQS (µg/m^3)**	**Greater than AAQS?**
PM_{10}	Annual	11	26	37	50	No
	24-hour	42	79	121	150	No

NO_2	Annual	10	27	37	100	No

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

Additional Impacts Analysis

Impacts on Soils, Vegetation and Wildlife

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

Air Quality Impacts Related to Growth

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

Regional Haze Analysis

The applicant conducted an AQRV analysis for the Class I areas. No significant impacts on these areas are expected. A regional haze analysis using the long-range transport model CALPUFF was conducted for the PSD Class I areas. The regional haze analysis showed no significant impact on visibility in these areas. Total nitrogen deposition rates on the PSD Class I areas were also predicted using CALPUFF. The maximum predicted nitrogen deposition rates are below the threshold levels recommended by the federal land manager.

Conclusion on Air Quality Impacts

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

5. CONCLUSION

The Department makes a preliminary determination that the proposed project will comply with all applicable state and federal air pollution regulations as conditioned by the draft permit. This determination is based on a technical review of the complete application, reasonable assurances provided by the applicant, and the conditions specified in the draft permit. Bruce Mitchell is the project engineer responsible for reviewing the application and drafting the permit documents. Cleve Holladay is the staff meteorologist responsible for reviewing the ambient air quality analyses. Jeff Koerner is the Air Permitting Supervisor responsible for reviewing and editing the draft permit package. Additional details of this analysis may be obtained by contacting the project engineer at the Department's Bureau of Air Regulation at Mail Station #5505, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400.