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Georgia-Pacific

Palatka Pulp and Paper Operations
Consumer Products Division
P.O. Box 919
Palatka, FL 32178-0919
(386) 325-2001

March 15, 2007

Mr. Jeffery F. Koerner, Air Permitting North Section
Bureau of Air Regulation
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Re: Project No. 1070005-038-AC PSD-FL-380
Modification of the No. 4 Recovery Boiler, No. 4 Lime Kiln and No. 4 Combination Boiler
Response to Request for Additional Information No. 3

Dear Mr. Koerner:

Please find enclosed five copies of the following attachments that were referenced but not included in the referenced document of March 14, 2007:

- Table 1-1 Contemporaneous Emissions with Power Boiler on Natural Gas
- Figure 1 – Simplified PFD for HVLC and LVHC gases

Sincerely,

Ron

Ron Reynolds, Environmental Engineer
Palatka Operations

cc: W. Galler, T. Champion, T. Wyles, S. Matchett, K.Wahoske, M. Curtis

Georgia-Pacific

COUNTY ROAD #216
FL180
PALATKA, FL 32178

Total pages: 13

To:	Bruce Mitchell	Location:	
Company:		Fax:	+1 (850) 921-9533
From:	Curtis, Michael	Return Fax:	207-827-0676
Date:	4/5/2007	Phone:	(386) 329-0918
Subject:	FW: BACT Analysis for No. 5 Power Boiler		

Please visit gp.com/supplier for important supplier information

Jeff,

Please find enclosed G-P Palatka's BACT analysis for CO for the #5 Power Boiler. This documentation will be submitted to the Department as a formal submittal via the US mail.

Mike Curtis

Environmental Superintendent

Palatka Mill Evironmental Division

(386)-325-0918

BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

No. 5 POWER BOILER

BACKGROUND

Both the U. S. Environmental Protection Agency (EPA) and the Florida Department of Environmental Protection (FL DEP) require that Best Available Control Technology (BACT) be applied to control emissions from a proposed new or modified source that triggers review under the federal Prevention of Significant Deterioration (PSD) regulations. In July 2006, the Mill submitted a combined PSD permit application for the Nos. 4 Lime Kiln, Recovery Boiler, and Combination Boiler. In order to address a PSD BACT issue related to sulfuric acid mist (SAM) emissions from the three pieces of process equipment, the Mill requested FL DEP to incorporate emission reductions from a separate project for the No. 5 Power Boiler into the netting table for the Nos. 4 Lime Kiln, Recovery Boiler, and Combination Boiler.

The No. 5 Power Boiler project will involve the conversion of this boiler from its current configuration of burning 100% No. 6 fuel oil to 100% natural gas by the end of 2007. This project is being done voluntarily by the Mill in order to exempt the No. 5 Power Boiler from the Best Available Retrofit Technology requirements. By implementing the changeover to burning 100% natural gas, future potential sulfur dioxide (SO_2) and SAM emissions from the No. 5 Power Boiler will be significantly reduced from the past actual emissions. By incorporating the emission reductions into the PSD netting table for the No. 4 Lime Kiln, No. 4 Recovery Boiler, and No. 4 Combination Boiler, both SO_2 and SAM emissions will be reduced to a level well below the respective PSD applicability levels for both of these pollutants. As a result, neither SO_2 or SAM emissions will trigger PSD. However, PSD is triggered for CO emissions as a result of the combined PSD project and the FL DEP has requested the Mill to perform a BACT analysis for CO emissions from the No. 5 Power Boiler.

The No. 5 Power Boiler will be equipped with low-NO_x gas-fired burners rated at 0.1 lbs/MM Btu. The resulting CO emission rate for the low-NO_x burners will be 0.185 lbs/MM Btu, based on the latest engineering information.

With regard to the state rules, BACT is defined as follows:

> *"Best Available Control Technology" means an emission limitation (including a visible emissions standard) based on the maximum degree of reduction for each pollutant emitted from or which results from the new or modified emissions unit which the Department on a case-by-case basis, taking into account energy, environmental and economic impacts and other costs, determines is achievable for such emissions unit through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combination techniques for control of each pollutant. In no event shall application of BACT result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under40 CFR Part 60 and 61 or any applicable emission standard established by the Department. If the Department determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit 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 emission reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results.*

The requirements for BACT were promulgated within the framework of the PSD regulations in the 1977 Amendments to the Clean Air Act (CAA) [Public Law 95-95; Part C, Section 165(a)(4)]. The primary purpose of BACT is to optimize consumption of PSD air quality increments and thereby enlarge the potential for future economic growth without significantly degrading air quality (EPA, 1978; 1980). Guidelines for the evaluation of BACT can be found in the EPA's Guidelines for Determining Best Available Control Technology (BACT) (EPA, 1978) and in the PSD Workshop Manual (EPA, 1980 and 1990 draft). EPA promulgated these guidelines to provide a consistent approach to BACT and to ensure that the impacts of alternative emission control systems are measured by the same set of parameters. In addition, through implementation of these guidelines, BACT in one area may not be identical to BACT in another area. According to EPA (1980):

BACT analyses for the same types of emissions unit and the same pollutants in different locations or situations may determine that different control strategies should be applied to the different sites, depending on site-specific factors. Therefore, BACT analyses must be conducted on a case-by-case basis.

The BACT requirements are intended to ensure that the control systems incorporated in the design of a proposed or modified facility reflect the latest in control technologies used in a particular industry and take into consideration existing and future air quality in the vicinity of the facility. BACT must, as a minimum, demonstrate compliance with the New Source Performance Standards (NSPS) for a source (if applicable). A cost-benefit analysis of the materials, energy, economic penalties, and the environmental benefits associated with a control system may also be necessary. A decision on BACT is to be based on sound judgment, balancing environmental benefits with energy, economic, and other impacts (EPA, 1978).

Historically, a bottom-up approach, consistent with the BACT Guidelines and PSD Workshop Manual, has been used. With this approach, an initial control level, which is usually NSPS, is evaluated against successively more stringent controls until a BACT level is selected. However, EPA developed a concern that the bottom-up approach was not providing the level of BACT decisions originally intended. As a result, in December 1987, the EPA Assistant Administrator for Air and Radiation mandated changes in the implementation of the PSD program, including the adoption of a new "top-down" approach to BACT decision-making.

The top-down BACT approach essentially starts with identification of the most stringent (or top) technology and emissions limits that have been applied elsewhere to the same, or a similar source category (Step 1). The applicant must next provide a basis for eliminating this technology in favor of the next most stringent technology or propose to apply the top technology (Step 2). Elimination of control alternatives may be based on technical and/or economic infeasibility. Such decisions are made on the basis of physical differences (*e.g.*, fuel type, etc.), location differences (*e.g.*, availability of water, etc.), or significant differences that may exist in the environmental, economic, or energy impacts. The differences between the proposed/modified facility and the facility on which the control technique was applied previously must be justified. The next step consists of ranking the remaining control technologies by control effectiveness (Step 3). Next, an evaluation of the most effective controls is conducted and documented (Step 4). Lastly, the BACT technology is selected from the list in the previous step (Step 5).

The EPA issued a draft guidance document on the top-down approach entitled, Top-Down Best Available Control Technology Guidance Document (EPA, 1990). However, to date, EPA has not promulgated the top-down approach for determining BACT.

In selecting one of the alternatives in technology, the applicant should consider application of flue gas treatment, fuel treatment and processes, and techniques that are inherently low polluting and are economically feasible. In cases where technological or economic limitations on the application of measurement techniques would make the imposition of an emission limitation infeasible, a design, operating, equipment, or work practice standard may be provided by the source. The BACT analysis shall include the following steps:

Step 1. Identify all potential control strategies.

Step 2. Eliminate technically infeasible options.

The demonstration of technical infeasibility should be clearly documented and should show, based on physical, chemical and engineering principles, that the technical difficulties would preclude the successful use of the control option on the emission unit under review.

Step 3. Rank remaining control technologies by control effectiveness.

The ranking should include relevant information including:

(a) control effectiveness
(b) expected emission rate
(c) expected emission reduction
(e) energy impacts
(f) environmental impacts
(g) economic impacts

Step 4. Evaluate most effective controls and document results.

The evaluation should include case-by-case consideration of energy, environmental and economic impacts. If top option is not selected as BACT, the evaluation should consider the next most effective control option.

Step 5. Select BACT.

BACT is the most effective option not rejected in Step 4.

The FL DEP's requirements for a BACT analysis are equivalent to the EPA's top-down approach. For this reason, this BACT document is consistent with both approaches.

BACT ANALYSIS-NO. 5 POWER BOILER FIRING 100% NATURAL GAS

This analysis is being conducted to determine the best available control technology for CO emissions from the No. 5 Power Boiler when burning 100% natural gas.

Step 1a-Identification of Control Technologies

Carbon Monoxide (CO) Emissions

There are several approaches that can be used to reduce carbon monoxide emissions from boilers. The first involves combustion modification techniques and a second approach involves the addition of post-combustion controls. The third technique involves the use of "good combustion practices". All three of these approaches are discussed below.

Combustion Modification-Overfire Air

The main combustion modification technique for reducing CO emissions is the use of an overfire air system. The reduction in CO emissions realized from this technique is highly dependent upon the uncontrolled CO concentration, combustion chamber oxygen content, distribution of the air (*e.g.*, portion of the air introduced through the burners versus through the overfire air ports), and type and method of fuel being fired. The use of an overfire air system ensures that complete combustion takes place, usually in the upper portion of a boiler's combustion chamber, to reduce the level of CO in the boiler exhaust gases.

The use of an overfire air system in a natural gas-fired boiler can reduce CO emissions up to 25% compared to CO emission levels in boilers without an overfire air system.

If a boiler is using other internal combustion modification techniques, such as low-NO_x burners, the CO concentration will tend to be higher than it would be in the absence of the low-NO_x burners. Combustion modification techniques, in general, have the goal of accomplishing complete combustion and reducing CO and NO_x emissions. Depending on the configuration of these systems and the distribution of air, in some cases NO_x may be reduced at the expense of increasing CO and vice-versa. It is a recognized fact that installing controls to reduce emission of one of these pollutants will raise emissions of the other pollutant. Generally speaking, however, facilities will attempt to achieve a balance between the emission levels of these two pollutants.

Post-Combustion Control-Oxidation Catalyst

The primary post-combustion technique used to reduce CO emissions is the use of an oxidation catalyst system. These conventional systems can provide between 70-95% reduction of CO emissions by passing the boiler flue gas exhaust through a catalyst bed that converts the exhaust gases to carbon dioxide and water vapor. These systems work best if the flue gas exhaust temperature is within the range of 600-1,100 °F, with an optimum temperature of about 800 °F. If the exhaust gas stream temperature of the combustion device in question is lower than the optimum temperature range, then additional heat is necessary in order to raise the temperature to the desired level. This may add significant operating costs to the control system since fuel must be burned in order to supply the additional heat.

The catalyst material for a CO oxidation catalyst system can be purchased from a number of catalyst manufacturers in the United States. However, the integration of the catalyst into a working module for installation on boiler exhaust gases may need to be handled by a separate company. These conventional catalysts work best when clean fuel(s) are being burned, such as natural gas, propane, or No. 1 or No. 2 fuel oil.

Good Combustion Practices

Another approach that can be used to minimize CO emissions from boilers is the use of "good combustion practices". Examples of "good combustion practices" for a natural gas-fired boiler include operator practices, maintenance practices, maintaining proper stoichiometric fuel-to-air ratios, monitoring of fuel quality and consistency, temperature, and combustion air distribution. Additionally, a start-up, shutdown, and malfunction plan should be developed and followed to ensure that emissions are minimized to the extent practicable during these periods of operation. All of these factors can affect the pollutant emission rate generated by the boiler, as well as the boiler combustion efficiency.

By following these "good combustion practices", CO emissions will be minimized. There is no specific percent reduction that can be given for using good combustion practices, however, without their use, CO emissions from a natural gas-fired boiler will increase significantly, by a factor of 100% or more, as compared to a boiler that uses good combustion practices. It is in the Mill's interest to use good combustion practices so that boiler efficiency is not compromised.

Step 1b-Identification of Control Technologies-Review of RACT/BACT/LAER Clearinghouse (RBLC)

Searches of the RACT/BACT/LAER Clearinghouse (RBLC) were conducted to identify technologies for the control of emissions from boilers with natural gas-fired burners. Searches were only conducted for RBLC determinations added during or after January 1980 and for large industrial sized boilers in service at pulp & paper mills. Listings of control technologies for boilers other than those at pulp & paper mills are too numerous to list and may not be representative of the types of boilers used in the pulp & paper industry. The RBLC technology listings are provided in Table 1, attached, and are summarized below.

> Table 1– good combustion control, none (or no controls), good combustion design and proper combustion techniques, efficient combustion, air/fuel ratio control.

Step 1c-Identification of Control Technologies-Review of Technologies in Use at Georgia-Pacific Corporation Facilities

Pulp & Paper Mills-Georgia-Pacific operates 18 pulp & paper mills in the United States. There are about 31 boilers at these facilities that are capable of burning natural gas, either alone, or in combination with other fuels. Of these 31 boilers, 6 have low-NO_x burners in place to reduce NO_x emissions and several others have overfire air systems to improve combustion efficiency and reduce CO emissions. There are no other types of pollution controls used for the natural gas burners since natural gas is the cleanest fuel available and it generates the smallest amount of pollution when combusted.

Step 2- Technical Feasibility Analysis

CO Control Technologies for Natural Gas-Fired Burners

In addition to the use of overfire air systems, the main control technology utilized for minimizing CO emissions from natural gas-fired burners is good combustion practices and the use of natural gas as clean fuel. Natural gas is the only fuel that will be utilized in the No. 5 Power Boiler. Good combustion practices and the use of natural gas are technically feasible for the No. 5 Power Boiler. An overfire air system is also technically feasible for the No. 5 Power Boiler, however, GP has obtained information from at least one vendor who has stated that its burners will minimize CO emissions to the same level of control as if an overfire air system were installed, but without the need to install an overfire air system.

Oxidation catalysts can also be used to remove CO emissions from a boiler with natural gas burners. A cost effectiveness analysis for an oxidation catalyst system will be performed later as part of this analysis.

Good combustion practices are technically feasible for the No. 5 Power Boiler.

Step 3 – Ranking the Technically Feasible Alternatives to Establish a Control Hierarchy

The next step in the BACT analysis is to rank the various control options not eliminated in the previous step. Table 2 below presents the remaining technologies.

TABLE 2 CO CONTROL TECHNOLOGY HIERARCHY

CONTROL TECHNOLOGY	CONTROL EFFICIENCY
Oxidation Catalyst	70-95%
Overfire Air System	Up to 25%
Good Combustion Practices **Use of Natural Gas as Clean Fuel**	No specific value

Step 4 – Control Effectiveness Evaluation

This step of the BACT process is necessary when the top control is not selected as BACT. Step 4 determines the economic impact of the feasible control options listed in Step 3 and then selects the most appropriate technology as BACT for the No. 5 Power Boiler. The economic analysis is based on cost data supplied by the equipment suppliers, GP experience at other locations, and the use of cost estimating spreadsheets contained in Chapter 2 of EPA's Office of Air Quality Planning & Standards (OAQPS) Control Cost Manual, 6^{th} Edition, January 2002 (Chapter 2-Cost Estimating Methodology).

Oxidation Catalyst

To estimate the cost for the purchase and installation of an oxidation catalyst system to reduce CO emissions from the No. 5 Power Boiler, GP prorated an estimate for a system that was designed for use with a gas turbine at its Old Town, ME Mill in 2001 (GP no longer owns the Old Town, ME Mill). The proration was performed by scaling up the costs based on the ratio of exhaust gas flow between the gas turbine and the No. 5 Power Boiler. The cost for a duct burner was also calculated since the exhaust gas temperature from the No. 5 Power Boiler is not high enough to allow the oxidation catalyst to work properly.

As stated earlier in this report, it is necessary to raise the exhaust temperature of the boiler in order for an oxidation catalyst system to work properly if the exhaust temperature is below the optimum value for the catalyst to work effectively. Since the No. 5 Power Boiler has an economizer section that recovers heat, the exhaust gas temperature is only 450 degrees Fahrenheit (°F). In order to work effectively, the exhaust gas temperature must be raised to approximately 800 °F for the catalyst to optimally reduce CO emissions. The use of a duct burner to raise the exhaust temperature from 450 °F to 800 °F, would require the Mill to burn approximately 420.5 MM ft^3 of natural gas per year at a cost of more than \$3.0 MM per year (based on gas cost of \$8.95/MM ft^3 Feb-2007)(see Addendum at end of this report). The use of a duct burner would also increase CO emissions by approximately 19.3 tons/yr. The potential CO emission rate from the boiler is 461 tons per year. Therefore, the total tons of CO generated would be equal to 461 + 19.3 = 480.3 tons/yr. Assuming a minimum CO reduction of 90% with the use of the CO catalyst system, 432.3 tons of CO would be removed. This equates to a cost effectiveness of \$8,454/ton as shown in Table 3.

This value is above any reasonable level of cost for reducing CO emissions. Therefore, it is economically infeasible to use an oxidation catalyst system to remove CO emissions. It is also a waste of a valuable energy resource (natural gas). In addition, the use of a duct burner increases the amount of CO due to the combustion of natural gas. For these reasons, an oxidation catalyst system for the No. 5 Power Boiler will not be discussed any further as part of this BACT analysis.

Overfire Air System

A cost effectiveness analysis for an overfire air system is not being performed as GP will be purchasing a natural gas burner system for the No. 5 Power Boiler without an overfire air system. However, the burner system that is installed will minimize CO emissions to a level equivalent to what would be possible with the installation of an overfire air system. For this reason, it is not necessary to perform a cost effectiveness evaluation for an overfire air system.

Good Combustion Practices

GP will utilize good combustion practices for the No. 5 Power Boiler at all times when the unit is in operation. For this reason, it is not necessary to perform a cost effectiveness evaluation for the use of good combustion practices.

Step 5 – Select BACT

CO Emissions

GP believes that boiler design and good combustion practices for the No. 5 Power Boiler represents BACT. This is equivalent to the "highest" BACT control technologies listed in Table 1 from the RBLC which indicates boiler design or good combustion practices. As discussed in Step 4 of this analysis, it is economically infeasible to use an oxidation catalyst system. Also as discussed in Step 4 of this analysis, GP will install a burner system that meets a CO emission level equivalent to that which would be achieved through the use of an overfire air system, but without actually installing an overfire air system.

The BACT emission limits for CO emissions contained in Table 1 range from 0.04 lb/MM Btu to 1.13 lb/MM Btu. The variation in emission rates is due to a number of variables, including boiler size and physical configuration, combustion design, year of manufacture, and whether or not the CO emission rate is based on original boiler design or retrofit design.

The Mill agrees to a CO BACT permit limit of 105.2 lbs/hr (or 0.185 lb/MM Btu), which is based on a vendor-supplied emission factor. This is the best CO emission rate attainable for the No. 5 Power Boiler based on the fact that the new, gas-fired burners will be designed with low-NO_x technology which results in a slightly higher CO emission rate than if the boiler was not equipped with low-NO_x burners. Additionally, the predicted CO emission rate is based on retrofitting an existing boiler with natural gas-fired burners, a fuel that the boiler was not originally designed to burn.

Addendum to BACT Analysis
Oxidation Catalyst for CO Removal:

To determine the amount of energy (H) it takes to heat the flue gas from 450 °F to 800 °F:

$H = m C_p (t_2 - t_1)$

Where: H = heat input, Btu/hr
m = mass flow rate of flue gas, lbs/hr = 505,500 lb/hr
C_p = specific heat of flue gas, Btu/lb-°F
$t_2 - t_1$ = 800-450 = 350 °F

Determine Cp for flue gas from Figure 3-12 of Perry's Chemical Engineers Handbook, 4th Edition, assume flue gas similar to air:

C_p = 0.25 Btu/lb-°F @ 800 °F

H = 505,500 lbs/hr x 0.25 Btu/lb-°F x 350 °F = 44,231,250 Btu/hr

Assuming a heat content of 1,000 Btu/ft^3 for natural gas, it will take 44,231,250 / 1,000 / 1.0E+06 = 0.044 MM ft^3/hr of natural gas to heat the flue gas from 450 °F to 800 °F. At a cost of $8.95/MM Btu for natural gas at the Mill, the hourly cost to raise the flue gas temperature to 800 °F is equal to 44.23125 MM Btu/hr x $8.95/MM Btu = $395.87/hr, or an annual cost of $395.87/hr x 8,760 hr/yr = $3,467,818 per year.

Natural gas-fired burners have a combustion efficiency of approximately 85%. Therefore, it will take a 44.23125 MM Btu/hr/0.85 = 52 MM Btu/hr burner to heat the flue gas up to 800 °F.

CO emissions from heating flue gas to 800 °F = (52 MM Btu/hr / 1,000 Btu/ft^3 /1.0E+06) x 0.084 lb/MM Btu (from AP-42, Table 1.4-1, and assuming heat content of gas = 1,000 Btu/ft^3) = 4.4 lb/hr x 8,760 hr/yr /2,000 lb/ton = 19.3 tons CO/yr. These CO emissions are generated in addition to those from the combustion of gas in the boiler, which are equal to 105.2 lbs/hr or 461 tons/yr. Total CO emissions, with the use of an oxidation catalysts system and a duct burner would be equal to 19.3 + 461 = 480.3 tons/yr.

TABLE 1
SUMMARY OF EPA CLEARINGHOUSE BACT DETERMINATIONS FOR
POWER BOILERS FIRING NATURAL GAS
CO EMISSIONS

COMPANY NAME	STATE	PERMIT NUMBER	PERMIT ISSUE DATE	PROCESS DESCRIPTION	BOILER SIZE	CONTROL DEVICE DESCRIPTION	EMISSION LIMIT	BASIS
GEORGIA-PACIFIC CORPORATION	MS	1500 00007	07/09/2003	POWER BOILER	766 MM BTU/HR	NONE	30.4 LB/HR (0.04 LB/MM BTU)	BACT PSD
WEYERHAEUSER COMPANY	AL	109 0001 X017, X018, X019	11/15/2002	BOILER, NATURAL GAS	300 MM BTU/HR	NONE	30.0 LB/HR (0.1 LB/MM BTU)	BACT PSD
GEORGIA-PACIFIC CORPORATION	LA	PSD-LA 581 (M 2)	01/25/2002	POWER BOILER NO. 5	987 MM BTU/HR	GOOD EQUIPMENT DESIGNS AND PROPER COMBUSTION TECHNIQUES	76.3 LB/HR (0.077 LB/MM BTU)	BACT PSD
GEORGIA-PACIFIC CORPORATION	LA	PSD-LA-581 (M 2)	01/25/2002	POWER BOILER NO. 2	65.5 MM BTU/HR	GOOD EQUIPMENT DESIGNS AND PROPER COMBUSTION TECHNIQUES	36.8 LB/HR (0.56 LB/MM BTU)	BACT PSD
GAYLORD CONTAINER CORPORATION	LA	PSD-LA 657	09/18/2001	BOILER NO. 10C	797.6 MM BTU/HR	GOOD EQUIPMENT DESIGN & PROPER COMBUSTION TECHNIQUES	886.3 LB/HR (1.13 LB/MM BTU)	BACT-PSD
RAYONIER SPECIALTY PULP PRODUCTS	GA	2631-151-12433	6/16/1997	BOILER, NATURAL GAS-FIRED	352 MM BTU/HR	GOOD COMBUSTION CONTROL	0.09 LB/MM BTU	BACT-PSD
WEYERHAEUSER COMPANY	MS	1680-00044	9/10/1996	BOILER, NATURAL GAS	400 MM BTU/HR	EFFICIENT OPERATION	0.1 LB/MM BTU	BACT-PSD
BOISE CASCADE CORP	AL	102-0001	5/10/1996	BOILER, NATURAL GAS	348.4 MM BTU/HR	COMBUSTION CONTROL	0.09 LB/MM BTU	BACT-PSD
CHAMPION INTERNATIONAL CORP	FL	PSD-FL 206	03/25/1994	NO. 4 POWER BOILER	533 MM BTU/HR	NONE	0.1 LB/MM BTU	BACT PSD
WAUSAU PAPERS	WI	99-DCF-079	10/28/1993	BOILER, NATURAL GAS	330 MM BTU/HR	GOOD COMBUSTION	0.12 LB/MM BTU	BACT-PSD
WILLAMETTE INDUSTRIES INC	LA	PSD-LA 562	02/04/1991	BOILER, GAS FIRED	335 MM BTU/HR	DESIGN & OPERATION	13.4 LB/HR (0.04 LB/MM BTU)	BACT PSD
GEORGIA PACIFIC CORPORATION	LA	PSD-LA 544	2/15/1988	BOILER, NATURAL GAS FIRED	987 MM BTU/HR	AIR/FUEL RATIO CONTROL	0.12 LB/MM BTU	BACT-PSD

TABLE 3 Cost Effectiveness for Using Oxidation Catalyst System to Remove CO Emissions from No. 5 Power Boiler

Cost Items	Cost Factors	2007 dollars
DIRECT CAPITAL COSTS (DCC):		
(1) Purchased Equipment Cost		
(a) Basic Equipment	Based on scaling up GP engineering cost analysis for similar system (14.9% adjustment from 2001 pricing based on CPI index)	$656,155
(b) Freight	0.05 x (1a)	$32,808
(c) Subtotal	(1a..1b)	$688,963
(2) Direct Installation	GP Engineering Estimate	$100,000
Total DCC:	(1) + (2)	$788,963
INDIRECT CAPITAL COSTS (ICC): (a)		
(3) Indirect Installation Costs		
(a) Technology License Fee	included with DCC (1a) above	$0
(b) Engineering & Supervision	included with DCC (2) above	$0
(c) Construction & Field Expenses	included with DCC (2) above	$0
(d) Construction Contractor Fee	included with DCC (2) above	$0
(e) Contingencies	(0.3) x (DCC) (GP Engineering estimate for retrofit)	$236,689
(4) Other Indirect Costs		
(a) Startup & Testing	GP Engineering Estimate	$50,000
(b) Working Capital	30-day DOC	$289,143
Total ICC:	(3) + (4)	$575,832
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC	$1,364,795
DIRECT OPERATING COSTS (DOC):		
(1) Operating Labor	$33/man-hr x 50 man-hr/yr	$1,650
Operator		$0
Supervisor		$0
(2) Maintenance		
Labor	15% of operating labor	$248
Materials		$0
(3) Costs for natural gas firing in duct burner	505,500 lbs flue gas/hr at 450 °F Heat exhaust gas from 450 °F to 800 °F Cost of natural gas = $8.95/MM Btu	$3,467,818
Total DOC:	(1) + (2) + (3)	$3,469,716
INDIRECT OPERATING COSTS (IOC):		
(5) Overhead	60% of oper. labor & maintenance	$1,139
(6) Property Taxes	1% of total capital investment	$13,648
(7) Insurance	1% of total capital investment	$13,648
(8) Administration	2% of total capital investment	$27,296
Total IOC:	(5) + (6) + (7) + (8)	$55,730
CAPITAL RECOVERY FACTOR (CRF)*:	n=yrs; i = %	0.0944
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.0944 times TCI (20 yrs @ 7%)	$128,827
ANNUALIZED COSTS (AC):	DOC + IOC + CRC	$3,654,273
POTENTIAL CO EMISSION RATE (TPY):	Potential Emission Rate = (0.185 lb/MM Btu x 568.9 MM Btu/hr) + 19.3 tons/yr of CO emissions from duct burner	480.3
TOTAL CO REMOVED TPY:	Oxidation catalyst = 90 % reduction in CO emissions	432.3
COST EFFECTIVENESS:	$ per ton of CO removed	$8,454

Notes:
Factors and cost estimates reflect vendor quotations, engineering estimates, and EPA's Cost Control Manual procedures
PEC based on GP engineering data for CO oxidation catalyst system for gas turbine in 2003 with rated exhaust flow of 323,093 lbs/hr
Cost = $365,000 (without installation)

***The CRF is computed according to the standard formula:**

$$CRF = i(1+i)^n/[(1+i)^n-1]$$

where: i = annual interest rate (decimal)
n = control system life (years)

Georgia-Pacific

Palatka Pulp and Paper Operations
Consumer Products Division
P.O. Box 919
Palatka, FL 32178-0919
(386) 325-2001

March 14, 2007

Mr. Jeffery F. Koerner, Air Permitting North Section
Bureau of Air Regulation
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Re: Project No. 1070005-038-AC PSD-FL-380
Modification of the No. 4 Recovery Boiler, No. 4 Lime Kiln and No. 4 Combination Boiler
Response to Request for Additional Information No. 3

Dear Mr. Koerner:

We are in receipt of your request for additional information, dated December 15, 2006, regarding our PSD permit application project to make modifications to the No. 4 Recovery Boiler, No. 4 Lime Kiln, and No. 4 Combination Boiler.

This response addresses questions 1, 3, 4 and 6 of the Department's December 15, 2006 request for additional information. A response to questions 2, 6 and 7 was submitted to FDEP on January 31, 2007. We are revising our January 31 response to question 6, which is why this question is addressed for a second time. GP will respond to question 5 in the near future, once it has determined all pertinent costs for the control of NO_x emissions for the No. 4 Combination Boiler.

This response also addresses a number of questions posed by the Department during a telephone conference call held on February 8, 2007 between Messrs. Bruce Mitchell and Jeff Koerner of the FDEP and Wayne Galler and Mark Aguilar of GP. The conference call was held to discuss a number of issues related to GP's desire to incorporate "past actual" and "future potential" emissions from the No. 5 Power Boiler into the most current PSD netting analysis, as well as GP's strategy for Best Available Retrofit Technology (BART) implementation at the Mill.

For ease of following GP's responses, we have repeated the FDEP's questions prior to the answers.

Sulfuric Acid Mist (SAM) Emissions

1. **The project is significant for sulfuric acid mist emissions and requires a BACT determination. SAM emissions from the No. 4 Lime Kiln result from firing residual oil; however, overall emissions are very low (estimated < 2 tons/year) due to the natural scrubbing action of the lime kiln and possible additional reductions in the venturi scrubber. For the No. 4 Combination Boiler, the control technology review indicates the following technologies are available for the control of SAM emissions: Dry ESPs, wet ESPs and wet scrubbers. Your control technology review for the No. 4 Recovery Boiler also indicates mist eliminators in addition to this equipment. Dry ESPs, wet ESPs, wet scrubbers were eliminated from consideration due to expected high capital costs. Mist eliminators were eliminated from consideration because no actual installations were identified that reduced SAM emissions with mist**

eliminators on a recovery boiler. However, this technology appears transferable. Please provide a cost effectiveness analysis for adding mist eliminators to the No. 4 Recovery Boiler and the No. 4 Combination Boiler.

As stated in the application for the No. 4 Recovery Boiler, reducing SO, emissions will also result in lower SAM emissions. For this reason, the Department will consider reducing the fuel sulfur content of the residual oil in making its BACT determination. Please provide a control technology review for lowering the fuel sulfur content of the residual oil currently being fired to include a cost effectiveness analysis.

Alternatively, provide a combination of fuel consumption/fuel sulfur limits that maintain the net emissions increases below the PSD significant emissions rate for SAM emissions (7 tons/year). Depending on future use, this may be readily achievable because the primary fuels are BI.S for the No. 4 Recovery Boiler and bark/wood for the No. 4 Combination Boiler. In fact, the stated purpose of the modifications to the No. 4 Combination Boiler is to more efficiently combust bark/wood and to displace oil firing.

Answer: The Mill plans to eliminate the use of No. 6 fuel oil in the No. 5 Power Boiler by the end of 2007. The Mill would like to incorporate the No. 5 Power Boiler's "past actual" and "future potential" emission rates into the Netting Table being used in the PSD permit application for the Nos. 4 Lime Kiln, Recovery Boiler, and Combination Boiler. By incorporating the No. 5 Power Boiler's "past actual" and "future potential" emissions into the Netting Table (see attached copy of Table 1-1 from PSD Application and associated emission calculations for the No. 5 Power Boiler), the SAM emissions change for the combined projects will fall well below the PSD applicability threshold of 7 tons per year and as a result, PSD will not be triggered for SAM emissions.

No. 4 Combination Boiler

3. **Prior to our previous request for additional information, representatives from the Bureau of Air Regulation met with representatives from Georgia-Pacific on October 26th. At the meeting, Georgia-Pacific indicated plans to revise the application to show that the modifications to the No. 4 Combination Boiler would not result in any emissions increases over baseline emissions except for CO emissions. Your response did not include such a revision. Please verify that you no longer have such plans to revise the application.**

   Answer: GP no longer plans to revise the PSD application as described.

4. **Your first response to our request for additional information (Item #14) identified the design flow as 230,000 acfm. Item #15 of that response also identified corrected flow rate as 135,400 dscfm @ 10% O_2, which was used to calculate the TRS emissions (page 7 of 7 of the application. "Total Reduced Sulfur, Potential Emissions"). Your second response to our request for additional information (Item #3) identifies the preliminary design flow rate as 317,000 acfm. It appears that the flow rate has changed. Please verify design flow rate from the No. 4 Combination**

Boiler in "acfm" and the corresponding flow rate in "dscfm @ 10% O_2. As necessary, recalculate the potential TRS mass emissions rates and update the applicable application pages.

Answer: As FDEP is aware, the Mill has submitted an application for modifying the No. 4 Combination Boiler so that it will be able to burn larger quantities of wood/bark. As a result of the modifications, the heat input rating for the boiler will be increased from the current value of 512.7 MM Btu/hr to 564 MM Btu/hr, for an increase of about 10%. As a result of the larger heat input and larger fuel firing rates for bark, there will be a corresponding increase in the exhaust gas flow rate when the boiler is operated at its maximum steam load. Based on an assessment prepared by the GP's Utilities Engineering Department, the estimated flow rate of the boiler's exhaust gases under full load at the higher heat input rating will be approximately 317,000 acfm at a temperature of approximately 500 ^{o}F. The exhaust flow rate at standard conditions is estimated to be approximately 135,400 dscfm @ 10% oxygen, or no change from the current standard exhaust gas flow rate. Since this standard flow rate is the same value that was used to estimate the TRS emission rate in the PSD application, no changes in the TRS emission calculations or application forms are necessary.

6. **Based on your last submittal, a new ESP will be installed on the No. 5 Power Boiler. No vendor has yet been selected. As you are aware, the No. 5 Power Boiler has been identified as a "BART-eligible" unit. Please ensure that this new control equipment will be designed and selected in accordance with this upcoming regulatory requirement.**

Answer: Once the Mill starts burning 100% natural gas in the No. 5 Power Boiler, which is planned to occur by the end of 2007, there will be no need to install a new ESP for this unit or continue to use the existing ESP. The modifications to the No. 5 Power Boiler are tentatively scheduled to begin in September 2007. Within 60 days of completing construction, the facility will complete compliance testing of the source.

Responses to Questions Posed by the Department during a Teleconference on February 8, 2007:

Question: The Department wants the Mill to describe the timing for putting the ESP into use to control particulate matter emissions during start-up for the No. 4 Recovery Boiler.

Answer: The ESP for the No. 4 Recovery Boiler is not energized and put into use until the end of the start-up period. This is because during the start-up period, there is a possibility of a spark from an energized ESP starting a fire or causing an explosion inside of the ESP. This can occur because during the start-up period when the boiler is burning 100% No. 6 fuel oil. There is a combination of some uncombusted fuel oil and a higher than normal level of oxygen in the exhaust gases from the boiler which are carried into the ESP. The higher than normal level of oxygen is present in the boiler because it is important to purge combustible gases from the boiler during start-up periods by using large volumes of combustion air. The wire electrodes in the ESP can become coated with the fuel oil and if the ESP is energized, a spark could develop in the ESP, resulting in a fire or explosion. For these reasons, the ESP is not energized until conditions inside the boiler have stabilized, meaning that the combustion temperature has risen to the proper level for steam to be produced and black liquor has begun to be used as a continuous source of fuel to the boiler. At this same time, the amount of fuel oil burned in the boiler is reduced until the boiler is firing 100% black liquor.

To minimize particulate emissions during the start-up period, the Mill utilizes good combustion practices such as maintaining the proper stoichiometric fuel-to-air ratio, monitoring of fuel quality and consistency, and proper temperature and combustion air distribution.

Question: The Department has asked the Mill to specify the SO_2 and NO_x emission limits the No. 4 Recovery Boiler can meet during start-up operations if the existing Title V Permit limits for normal operation are not sufficient.

Answer: Since the No. 4 Recovery Boiler burns 100% No. 6 fuel oil during start-up (no black liquor), the Mill is requesting separate emission limits for SO_2, NO_x, and PM emissions during start-up, without the use of the ESP. These limits should be based on emission factors for a large (>250 MM Btu/hr heat input) fossil-fuel fired industrial boiler contained in Table 1.3-1 of AP-42 and assuming a maximum fuel oil firing rate of 80 gallons per minute with a sulfur content not to exceed 2.35% (wt.). The emission calculations are shown below:

SO_2 (lbs/hr) = (157 x 2.35 % S) lb SO_2/1,000 gal fuel oil fired x (80 gal fuel oil fired/min/1,000 gallons) x 60 minutes/hr = 1,771 lbs SO_2/hr

NO_x (lbs/hr) = 47 lb SO_2/1,000 gal fuel oil fired x (80 gal fuel oil fired/min/1,000 gallons) x 60 minutes/hr = 225.6 lbs NO_x/hr

PM = [(9.19 x 2.35% S) + 3.22] lbs PM/1,000 gal fuel oil fired x (80 gal fuel oil fired/min/1,000 gallons) x 60 minutes/hr = 119.1 lbs PM/hr

PM_{10} = 74.8% of PM (AP-42, Table 10.2-3) = 89.1 lbs/hr

Question: The Department has requested the Mill to provide the number of hours per year that the waste gases from the pulp mill are incinerated in either the No. 4 Combination Boiler or the No. 5 Power Boiler.

Answer: Following is a listing of the hours during 2004 through 2006 that the non-condensable gases (NCGs) and stripper off-gases (SOGs) from the pulp mill were incinerated in either the No. 4 Combination Boiler or the No. 5 Power Boiler. Effective April 2006, all high volume, low concentration (HVLC) gases, also referred to as dilute NCGs (DNCGs), must be burned in an incineration device. For the Palatka Mill, the primary incineration device for the DNCGs is the No. 5 Power Boiler with the No. 4 Combination Boiler as the back-up incineration device:

2004: No. 4 Combination Boiler NCGs-915 hours SOGs-886 hours

2005: No. 4 Combination Boiler NCGs-905 hours SOGs-763 hours
DNCGs-924 hours
No. 5 Power Boiler DNCGs-149 hours

2006 No. 4 Combination Boiler NCGs-1,174 hours SOGs-901 hours
DNCGs-3,436 hours
No. 5 Power Boiler DNCGs-4,920 hours

Question: The Department has requested the Mill to provide the typical time period for a "warm" start up period for the No. 4 Recovery Boiler. The Department also wants the Mill to provide information on the number of actual start-ups during the last 2 years.

Answer: A typical "warm" start-up period for the No. 4 Recovery Boiler is approximately 8 hours. This is opposed to a typical "cold" start up period that may last 24 hours or greater as explained to the FDEP in the response to RAI # 2, dated January 31, 2007. Start-up periods for the No. 4 Recovery Boiler:

	2005	2006
Cold start-ups	1	3
Warm start-ups	3	8

Question: The Department has requested the Mill to provide a simplified process flow diagram (PFD) indicating the primary and back-up control devices used to control emissions from the facility's waste gas streams.

Answer: A simplified PFD has been prepared and is attached as Figure 1.

In a recent teleconference the Department requested the specifications for the low-NO_x natural gas burners proposed for the No. 5 Power Boiler. The Mill's engineering specification for the burners is attached. The manufacturer's specification will be provided when available.

If you have any questions regarding this response, please contact Michael Curtis at 386-329-0918.

I, the undersigned, am the responsible official of the source for which this document is being submitted. I hereby certify, based on the information and belief formed after reasonable inquiry, that the statements made and the data contained in this document are true, accurate, and complete.

Sincerely,

Al Kahn For KWW

Keith W. Wahoske
Vice President

Attachment

cc: W. Galler, T. Champion, T. Wyles, S. Matchett, R. Reynolds, M. Curtis - GP

PART 1 - GENERAL

1.1 SCOPE

1.1.1 No. 5 Power Boiler at G-P's Palatka, Florida mill fires No. 6 fuel oil. It is a top hung field-erected boiler furnished by Babcock and Wilcox. It has a pressurized furnace. This boiler will be converted to natural gas firing. The boiler presently has its original burners, manufactured by Forney Engineering. Burner delivery is critical. All items specified in this document shall be at the jobsite no later than September 1, 2007.

1.1.2 Equipment shall be built to all applicable codes and standards including FM standards.

1.1.3 Two drawings are included:

- Front & Sectional Front View of No. 5 Power Boiler, B&W drawing no. 218 72 F-2
- Existing burner arrangement, Forney Engineering drawing 8901-1

1.2 REFERENCED AND INCLUDED GEORGIA PACIFIC SPECIFICATIONS

1.2.1 GE01011-002 General Conditions

1.2.2 GE01014-001 Drafting and Document Standards

1.2.3 ME09914-001 Equipment Balance

1.3 FURNISHED BY SELLER

The following is a list of items to be supplied by the Seller. This list is not intended to be all inclusive; it is only a general list. The Seller is to include all items which are required to constitute a complete unit and system.

1.3.1 Natural gas burner and igniter assemblies including:

1.3.1.1 Natural gas igniters and igniter scanners

1.3.1.2 Main flame scanners

1.3.1.3 All required flex hoses

1.3.1.4 Registers with automatic operators

1.3.1.5 Internal insulation (if required)

1.3.1.6 Tile template for throat (if required)

1.3.2 Factory assembled, rack-mounted burner valve train including:

1.3.2.1 All required safety shutoff valves and vent valves

1.3.2.2 All required limit switches and pressure switches

1.3.2.3 Gas pressure regulators and relief valves

1.3.2.4 All required pressure gauges

1.3.2.5 Included piping

1.3.3 If required, additional equipment to achieve specified NOx emissions

1.3.3.1 FGR fan and motor

1.3.3.2 FGR control damper

1.3.3.3 Flue gas ducting

1.3.3.4 Engineering

1.3.4 Windbox air flow modeling using CFD to optimize air flow

1.4 DRAWINGS

1.4.1 The Seller shall furnish the Engineers with all information, drawings, and instructions required for complete execution of the work. See attached Drawing and Document Requirement Sheet.

1.5 PROPOSAL

The proposal shall include the following information:

1.5.1 Full descriptive literature for each piece of equipment and a schematic outline drawing shall accompany the proposal. The weights of the major pieces of equipment shall also be included.

1.5.2 Normal delivery from date of purchase shall be provided along with options for improving that delivery date.

1.5.3 A listing of all motors furnished with their rated horsepowers and RPM.

1.5.4 The attached tabulation sheets shall be completed by the Seller.

1.5.5 Optional accessories recommended, if any.

1.5.6 Proposal shall include any exceptions to the specifications.

1.6 OPTIONS

1.6.1 Furnish an optional price for including flame rod detection of igniter flames rather than scanners.

PART 2 – DESIGN & MATERIALS

2.1 DESIGN CRITERIA

2.1.1 Design heat input with all burners in operation at 100% Maximum Continuous Rating (MCR): 535.5 million Btu/hr

2.1.2 Steam generation at 100% MCR: 420,000 lb/hr

2.1.3 Individual burner turndown shall be 8:1

2.1.4 Normal boiler operating range is 10% to 100% of MCR

2.1.5 Natural gas HHV=1,050 Btu/CF

2.1.6 Nominal natural gas pressure = 120 psig

2.1.7 NOx Emissions shall not exceed 0.10 lb/10^6 Btu heat input over the specified burner turndown range with any number of burners in operation.

2.1.8 CO Emissions shall not exceed 0.185 lb/10^6 Btu heat input over the specified burner turndown range with any number of burners in operation.

2.1.9 Air leakage ("cooling air") through unused burners shall be minimized through materials of construction and other design features.

2.1.10 When operating, burners shall use a minimum of excess air.

2.2 MATERIALS & CONSTRUCTION

2.2.1 Number of burners: Six total, three rows of two burners per row.

2.2.2 Furnace pressure at 100% MCR is 9.8 inches water gage with the existing fuel oil burners.

2.2.3 Maximum flue gas temperature at the air heater outlet is 470^{0}F.

2.2.4 Burners shall fit in place of the existing oil burners with minimum windbox modifications and no pressure part modifications.

2.2.5 Burners shall be started and stopped remotely.

2.2.6 Igniters

2.2.6.1 Igniters shall be natural gas, not spark.

2.2.6.2 Intermittent igniters are preferred.

2.2.6.3 Scanners shall be used to prove igniter flames.

2.2.7 Shop assembled valve racks with interconnecting piping shall be furnished.

2.2.7.1 Connections to each burner valve train shall be: gas inlet, gas out to burner, gas out to igniter, vent out.

2.2.7.2 The valve train for each burner shall contain safety valves, vent valves and control valves along with provisions for necessary instrumentation.

2.2.7.3 Two valve racks shall each contain two burners' valves with one burner valve train above the other train. These two racks shall be opposite hand.

2.2.7.4 Valve train shall include provisions for automated leak checking.

2.2.7.5 Each valve rack shall fit within these dimensions: 8' long, 2 ½' deep, 6' high.

2.2.8 Flex hoses shall be selected for a boiler movement shown on the included B&W drawings.

2.2.9 The flue gas recirculation (FGR) fan shall be direct driven. Its test block margins on capacity and pressure shall be large enough to ensure that the fans will meet their net conditions when installed.

2.2.9.1 Sleeve bearings and antifriction bearings are acceptable.

2.2.9.2 The first critical speed shall be 125% of the operating speed.

2.2.9.3 Fans with 3,600 rpm are not allowed

2.2.9.4 Fans with 1,800 rpm are permissible with drivers of 125 horsepower and less. Fans with drivers larger than 125 horsepower shall have a maximum speed of 1,200 rpm.

2.2.9.5 Fans shall have its rotor supported between the bearings (Arrangement 3). Independent bearing pedestal supports shall be provided with separate sole plates which may be permanently mounted in place.

2.2.9.6 Material handling fans shall have radial bladed wheels with stiffeners and sufficient strength to resist an unbalanced condition of the rotor caused by wear on the blades. Renewable blade, scroll, and side plate liners of 350 Brinell minimum abrasion resistant materials shall be furnished.

2.2.9.7 Fans shall be furnished with motor, coupling and approved coupling guard, installed and aligned when possible. 200 HP and larger motors shall be 4160 v. Smaller motors shall be 480 v.

2.2.10 FGR system design

2.2.10.1 FGR ductwork shall have a minimum wall thickness of 0.100". Round ductwork is preferred.

2.2.10.2 Nonmetallic expansion joints with material selected for the maximum flue gas temperature shall be used.

2.2.10.3 Control dampers shall be designed for the maximum flue gas temperature. Air cooled damper bearings are preferred.

2.2.11 All seller–furnished natural gas piping shall be painted yellow.

PART 3 – EXECUTION

3.1. FURNISHED BY BUYER

3.1.1. Burner management system

3.1.2. Scanner cooling air supply

3.1.3. Installation

3.1.4. Wiring

3.1.5. Piping

3.1.6. Startup

APPENDIX A

OWNER TECHNICAL DATA SHEET

Equipment Identification:

Equipment Name: Low NOx Natural Gas Burners

Project Number: TBD

GP Equipment Number: TBD

Mill Location: Palatka, Florida

Process Conditions: Per Section 2.1 Design Criteria

Equipment Requirements: Per Section 2.2 Materials & Construction

Paint Color: Seller's Standard

Comments:

APPENDIX B

SELLER TECHNICAL DATA SHEET

All blanks in this Data Sheet must be filled in by the Seller. The completed form shall be submitted by the Seller with the equipment quote.

General Equipment Information

Seller: ______________________________

Equipment Identification: ______________________________

Georgia Pacific Project Number: ______________________________

Georgia Pacific Equip Name & Number: ______________________________

Georgia Pacific Millsite: ______________________________

Drive Requirements: ______________________________

Seal Water Requirements: ______________________________

Lubrication Requirements: ______________________________

Design Weights (Approximate, Pounds: ______________________________

Shipping Weight (Incl Approx Wt Of Crate, Pounds: ______________________________

Manufacturing / Assembly Location: ______________________________

Quote Options: ______________________________

Equipment Components: ______________________________

APPENDIX C

COMMERCIAL OPTIONS

This form must be filled out by the Seller and be submitted with all quotes.

Seller: ______________________________

Proposal Identification: ______________________________

Georgia Pacific Project Number: ______________________________

Georgia Pacific Equip Name & Number: ______________________________

Georgia Pacific Millsite: ______________________________

Base Pricing Quotes:

Equipment Proposal ______________________________

Shipping Weight of all Materials ______________________________

Freight Cost FOB Mill Site ______________________________

Delivery Time (After PO) ______________________________

Optional Costs:

Spare Parts Listing ______________________________

Misc. Special Tools ______________________________

Terms ______________________________

APPENDIX D
PERFORMANCE AND OPERATIONAL GUARANTEE

The Seller guarantees that Process Conditions and Performance Measures called out in Appendix A shall be met. Also, the Seller guarantees the following:

- Guarantee the specified heat input based on the specified natural gas.
- Guarantee the specified emissions rates over the specified operating range.
- Predict and guarantee the excess air required in terms of percent oxygen, dry volumetric basis, measured at the generating bank outlet.
- Predict and guarantee the air leakage through idle burners in terms of O_2 in flue gas at 33% load with two burners operating and the remaining burners idle.
- If FGR is required, predict and guarantee NOx emissions without FGR in operation.
- Predict and guarantee the required windbox pressure ant 100% MCR.

PERFORMANCE WARRANTY

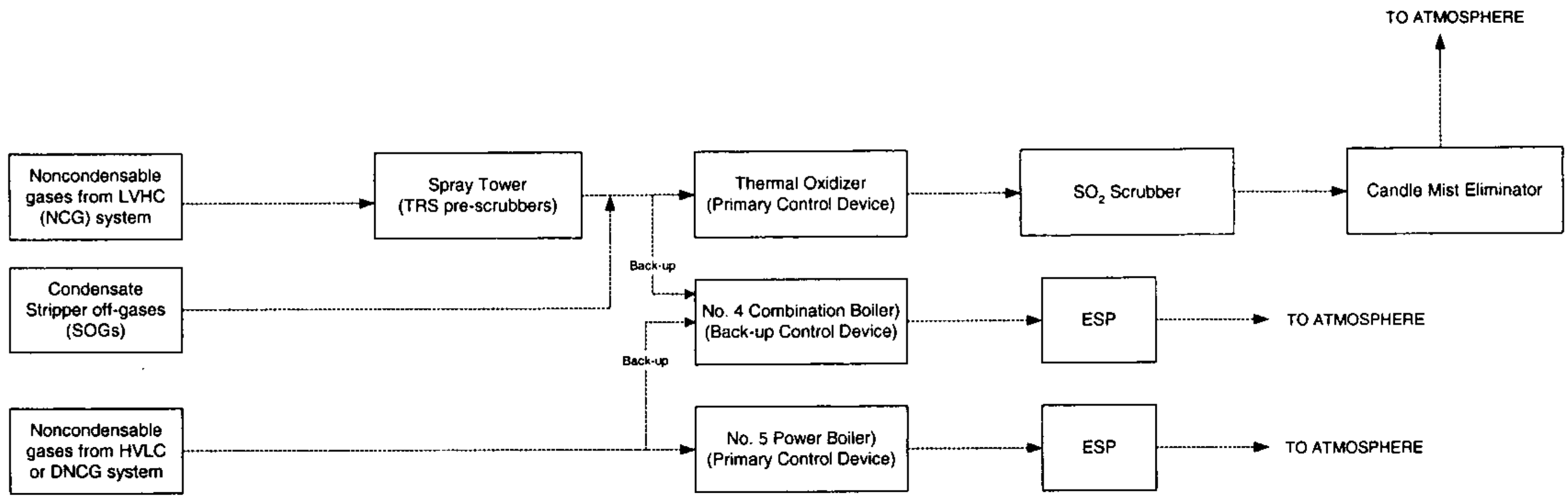
Warranties: The seller shall guarantee performance of the equipment in this specification. The seller shall have mechanical defects warranty for a period of 12 months from startup or 18 months after shipment, whichever occurs first.

In addition, Seller must demonstrate that the Equipment meets each element of the following Performance Warranty.

TESTING PROCEDURES

- Performance testing will be witnessed by the OWNER or by an OWNER appointed representative.
- Performance testing schedules will be approved by the OWNER.
- The SELLER will provide all testing documentation to the OWNER.
- If any test is unsuccessful, it will be repeated following evaluation and adjustments made as necessary on the Equipment. If still unsuccessful, SELLER to promptly and immediately correct any faults with all necessary steps that are needed, including manufacture or purchase of parts locally for delivery to mill site if deemed necessary.
- No third party will be present, nor given access to any test data without the written consent of the OWNER.
- The costs and expenses of SELLER'S personnel involved shall be borne by the SELLER.

FIGURE 1
SIMPLIFIED PROCESS FLOW DIAGRAM FOR
LVHC AND HVLC EXHAUST GASES



Note: Examples of low volume high concentration (LVHC) gases include emissions from digesters, evaporators, and concentrators

Note: Examples of high volume low concentration (HVLC) gases, also referred to as dilute non-condensable gases (DNCGs), include emissions from brown stock washers, pressure knotters, bleach plant pre-washer, oxygen delignification system, softwood and hardwood high density storage tanks.

TABLE 1-1
CONTEMPORANEOUS AND DEBOTTLENECKING EMISSIONS ANALYSIS AND PSD APPLICABILITY
INCORPORATION OF NO. 5 POWER BOILER FIRING 100% NATURAL GAS

Source Description	Pollutant Emission Rate (TPY)										
	SO_2	NO_x	CO	PM	PM_{10}	VOC	TRS	SAM	Lead	Mercury	Fluoride
Future Potential Emissions											
No. 4 Combination Boiler - 2.35% S [a]	835.5	496.5	1,010.5	80.8	59.8	34.4	---	36 8	0.097	0.0071	0 095
No. 5 Power Boiler firing 100% natural gas [h]	1.5	311.5	209.3	18.9	18.9	13.7	---	0.0	1.25E-03	6.48E-04	0
No. 4 Lime Kiln: annual: 20 ppmvd TRS	40.0	297.4	71.5	130.2	128.0	41.4	25.1	1.8	0.25	--	--
No. 4 Recovery Boiler [c]	153.9	738.1	2,245.6	331.1	248.3	92.0	34.2	15.9	0.014	8.3E-05	--
No. 4 Smelt Dissolving Tank [d]	33.7	69.6	11.4	55.2	49.7	115.0	14.9	--	0.013	8.3E-05	--
Black Liquor/Green Liquor Tanks [d]	--	--	--	--	--	14.0	3.7	--	--	--	--
Caustic Area [d]	--	--	--	2.6	2.6	18.9	5.8	--	--	--	--
Other Projects [g]											
Bark Handling System	--	--	--	22.8	13.9	475.8	--	--	--	--	--
Total- Future Potential	**1,064.6**	**1,913.1**	**3,548.3**	**641.7**	**521.3**	**805.2**	**83.7**	**54.5**	**0.38**	**0.0079**	**0.095**
Past Actual Emissions [f]											
No. 5 Power Boiler (2004-2005 data) [h]	3,316.4	459.6	48.9	193.6	166.5	2.7	---	145.9	0.015	0.0011	0.365
No. 4 Combination Boiler [b]	820.4	413.2	780.3	99 2	71.9	22.4	--	36.1	0.065	0.0047	0.084
No. 4 Lime Kiln	0.04	101.4	6.8	51 3	50.4	2.5	2.6	0.0018	0.16	--	--
Bark Handling System	--	--	--	14.6	10.6	175.4	--	--	--	--	--
No. 4 Recovery Boiler	14.7	473.2	1,249.3	134.7	101.0	9.5	11.3	1.50	0.012	6.8E-05	--
No. 4 Smelt Dissolving Tank [d]	27.7	57.1	9.4	34.9	31.4	94.4	5.1	--	0.010	6 8E-05	--
Black Liquor/Green Liquor Tanks [d]	--	--	--	--	--	9.7	3.0	--	--	--	--
Caustic Area [d]	--	--	--	1.7	1.7	12.6	4.0	--	--	--	--
Total- Past Actual	**4,179.2**	**1,504.5**	**2,094.7**	**530.0**	**433.5**	**329.2**	**26.0**	**183.5**	**0.26**	**0.0059**	**0.449**
Increase Due to Project	**-3,114.6**	**408.6**	**1,453.7**	**111.7**	**87.7**	**476.0**	**57.7**	**-129.1**	**0.11**	**0.0020**	**-0.354**
PSD SIGNIFICANT EMISSION RATE	40	40	100	25	15	40	10	7	0.6	0.1	3.0
Netting Triggered?	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	No	No	No
CONTEMPORANEOUS EMISSION CHANGES											
MACT I Compliance Project (9/00) (Permit nos. 1070005-007-AC and -017-AC) - startup 2002											
--Increase Due to New Thermal Oxidizer	109.7	151.4	8.8	30.7	30.7	9.1	0.89	7.7	--	--	--