Georgia-Pacific

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BUREAU OF AIR REGULATION

Jeffrey F. Koerner, P.E. Permitting North Administrator
Bureau of Air Regulation
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

RE: Modification to the Nos. 4 Combination Boiler, Lime Kiln and Recovery Boiler
Project No.: 1070005-038-AC/PSD-FL-380

Dear Mr. Koerner:

On August 18, 2006, GP received a Request for Additional Information (RAI). Our responses to your questions and comments are presented in this letter. In preparing this response, we were very disappointed to find that many of the questions and comments had nothing to do with the permit applications at issue, but instead were asking the Mill to substantiate and defend data and assumptions that were part of past air permitting actions where final permits have long since been issued. This greatly added to the time that it took for us to prepare this response and we are concerned that this action will further delay issuance of our final permit. Furthermore, we strongly believe that data and facts reviewed in prior applications that resulted in a permit being issued should be stipulated as already having been approved by the Department and not subject to further review. Questions No. 1-3 and 5-8 fall into this category.

In order to facilitate planning and scheduling for the 2007 mill outage, GP has asked that the Recovery Boiler / Lime Kiln Projects (fully funded) portions of this application be issued as a separate permit from the No. 4 Combination Boiler Project (unfunded). Our Environmental Attorney, Mr. Scott Matchett recently contacted you to further inquire regarding the Department's ability and predilection to grant this request. GP would like to meet with you very soon to resolve this issue.

For ease of review, we have restated the Department's questions and comments prior to our responses.

No. 4 Combination Boiler (NO. 4 CB)

1. In Attachment GP-EU1-F1.8, specifically in Section 1.A., LVHC NCGs, a claim of "at least 60%" sulfur removal efficiency in the pre-scrubber is made. How was this minimum efficiency established? Do you have any performance tests/documentation to support this claim? Please provide any test reports/documentation to support this efficiency removal claim.

This assumption was established during the initial Cluster Rule permitting completed in 2000. It has been used in subsequent permit revisions. In each of these cases, the Department has reviewed and approved this assumption. As such, it is unclear why this issue is being re-visited as part of this permitting action. With that said, the 60% value was a conservative estimate since the pre-scrubber uses white liquor, which is highly alkaline (pH >= 9), and theoretically would remove much higher quantities of sulfur from the non-condensable gas (NCG) stream. We have not found actual test data where the sulfur removal efficiency (*i.e.*, inlet and outlet sulfur concentration in the gas stream) of the pre-scrubber has been measured. As stated several times in the application, the proposed project for the No. 4 CB will in no way affect the manner in which NCG/SOG/DNCG gases are burned in the boiler or the emissions resulting from such burning.

2. In Attachment GP-EU1-F1.8, specifically Sections 1.A, B. and D., provide documentation of the emission factors used, i.e., 378 lbs S/hr loading from the LVHC gas stream, 162 lbs S/hr from the SOG stream and 0.35 lbs S/hr from the DNCG stream, respectively.

These emission factors were established during the initial Cluster Rule permitting completed in 2000/2001, and the Brown Stock Washer permitting in 2004. The LVHC gas stream factors have been used in subsequent permit revisions. In each of these cases, the Department has reviewed and approved the factors. As such, it is unclear why this issue is being re-visited as part of this permitting action. The LVHC gas stream factors were based on a sulfur balance and documented in Table 3-1 of the November 2001 Revised MACT I permit application. The factors for the SOG and DNCG streams are based on NCASI factors and documented in Attachments GP-EU1-G8a & b in the October 2003 MACT 1 BSW/OD project Air permit application. Copies of these tables are in Attachment K.

3. In Attachment GP-EU1-F1.8, specifically Section 2, Maximum 24-hr SO_2 Emission Rate, what is the basis of the 2300 TPD ADUP pulp production rate used in the calculations? Has this level of production ever been achieved? If Not, then identify equipment changes/modifications and/or replacements will have to be made in order to achieve this level of operation?

The 2300 air dried tons of unbleached pulp value was approved by the Department in Air Permit No. 10070005-024-AC and is based on three BSW's achieving a 750 to 770-ton-per-day (TPD) rate (nominal) each. Individually, since start up of the #7 BSW in November 2005, each BSW has been able to wash pulp at a rate of at least 32 air dried tons of unbleached pulp per hour (ADTUP/hour), which if sustained for a full day would result in the mill demonstrating the 2300 TPD value.

Again, it is unclear why this issue is being re-visited as part of this permitting action when these projects have no impact on actual production or capacity. Also, the Department has full documentation on the basis of the 2300 TPD production level from past permitting actions.

4. During a loss of bark feed and a switch to 100% fuel oil firing, do you plan, as a method of operation, to burn the DNCGs, NCGs and SOGs in the No. 4 CB, or will they routed to the No. 5 Power Boiler (No. 5 PB) or some other emissions unit for destruction? Please explain and adjust any calculations that is/are appropriate.

Our plans are to combust the NCG/SOG gases in the Thermal Oxidizer. When the Thermal Oxidizer is unavailable we will combust the gases in the No. 4 CB. The Title V Permit authorizes the combustion in the boiler up to 20% of the time. Likewise, the DNCG gases are currently combusted in the No. 5 PB with the backup as the No. 4 CB. In our view, the combustion time in the Combination Boiler has already been constrained when burning the NCG/SOG gases. No further benefit is provided by limiting which boiler will burn the DNCGs because the boiler stacks are the same height and located adjacent to each other. Also, the sulfur dioxide emission calculations in the application reflect the worst-case condition of 100% fuel oil and burning the total reduced sulfur (TRS) gases in the No. 4 CB for up to 20% of the time.

As stated several times in the application, the proposed project for the No. 4 CB will in no way affect the manner in which NCG/SOG/DNCG gases are burned in the boiler, or the emissions resulting from such burning. This was clearly stated in our application. We do not believe that any adjustments in the calculations are needed as part of the permitting action.

5. For the annual SO_2 emissions calculations in Attachment GP-EU1-F1.8, what is the basis for the "20% utilization of the No. 4 CB for the destruction of NCGs, SOGs and DNCGs"? Please explain and provide justification. Adjust any calculations that is/are appropriate. When in this mode, how are you demonstrating compliance with the TRS limit?

This operational scenario was established during the initial Cluster Rule permitting completed in 2000. It has been used in subsequent permit revisions. In each of these cases, the Department has reviewed and approved the scenario. It is based on the assumption that the No. 4 CB, as a worst-case operating scenario, would be utilized as a backup destruction device 20% of the time on an annual basis.

As stated in Condition C.12 of the current Title V operating permit (Permit No. 1070005-034-AV), compliance with the TRS limit of 5 ppmvd at 10% oxygen is achieved by maintaining the minimum temperature of 1,200°F and 0.5 second residence time. Documentation that these requirements were being met was submitted to the Department in a report from Mr. David Buff to Ms. Rita Felton-Smith dated June 30, 2004 in conjunction with the application process for Permit No. 1070005-024-AC. A copy of that report is included in Attachment A.

Again, it is unclear why this issue is being re-visited as part of this permitting action when these projects do not affect the manner in which NCG/SOG/DNCG gases are burned in the boiler or the emissions resulting from such burning. This was clearly stated in our application.

6. Is the thermal oxidizer, which is the primary destruction device for NCGs and SOGs, down 20% of the operational year? If so, please explain. In addition, provide the hours of operation and downtime for the thermal oxidizer for the last five years.

No, the Thermal Oxidizer (TO) has not been down 20% of the time over the past four years. As the primary destruction device for NCG/SOG gases, the TO has been used to burn NCG/SOG gases about 85-90% of the time. As the Department is aware, the Thermal Oxidizer did not operate the first four months of 2002. It was started up in May 2002. The hours of operation of the Thermal Oxidizer (which includes times when the TO was burning natural gas and NCGs were being burned in the No. 4 CB) are as follows:

2002 - 5,720 hours, 2003 – 8,547 hours, 2004 – 7,772 hours, 2005 – 8,687 hours

While not specifically tracked on a daily basis, the downtime hours for the Thermal Oxidizer are estimated as follows:

2002 - <1,000 hours (from 4/16/02 to 12/31/02), 2003 - 213 hours, 2004 – 1,012 hours, 2005 - 75 hours

Again, it is unclear why this issue is being re-visited as part of this permitting action when these projects do not affect the manner in which NCG/SOG/DNCG gases are burned or the emissions resulting from such burning. This was clearly stated in our application.

7. While the thermal oxidizer is operating, have you ever routed the NCGs and SOGs to the No. 4 CB or another emissions unit for destruction? If yes, please explain.

Yes, to better control the flame in the TO while doing adjustments we sometimes simultaneously burn NCGs in the TO and the SOGs in the No. 4 CB. The NCG or SOG gases are sent to the combination boiler any time we need to work on the TO flame scanners, instrumentation, or other for other maintenance needs. While these maintenance activities are taking place, we have burned only NCGs or only SOGs in the Thermal Oxidizer and the other gas stream in the No. 4 CB. However, this is done on a limited time basis and operation in this manner is allowed by our construction and TV permits.

It is unclear why this issue is being re-visited as part of this permitting action when these projects do not affect the manner in which NCG/SOG/DNCG gases are burned, or the emissions resulting from such burning. This was clearly stated in our application.

8. When the No. 4 CB is used as a backup control device for NCGs, SOGs, and DNCGs, how is compliance demonstrated? For the years that the No. 4 CB has been used as a backup control device for the thermal incineration system, provide the number of hours of operation in this backup control mode and the percent of total operation of the No. 4 CB in this backup control mode. Is the No. 4 CB also the primary control device for DNCGs (see Page 2-8)? When the No. 4 CB is used as the control device for NCGs, SOGs, and DNCGs, do the controlled emission levels comply with the NESHAP, 40 CFR 63, Subpart S?

It is very surprising that the Department is even asking this question, as the monitoring requirements, which are consistent with the Cluster Rule, are clearly spelled out in Condition C.12 of the current Title V operating permit (permit No. 1070005-034-AV), which recognizes that compliance with the TRS limit of 5 ppmvd @ 10% oxygen is achieved by maintaining the minimum temperature of 1,200°F and 0.5 second residence time. The compliance demonstration method is documentation that these requirements were being met and proper documentation was submitted to the Department as stated in our response to Question 5 of this RAI.

The use of the No. 4 CB to burn NCG/SOG/DNCGs is documented in annual reports to DEP. The time that the No. 4 CB was operating, was used as a backup device to the Thermal Oxidizer to burn NCG/SOG gases, and the percent of total operating time that NCG/SOG gases were burned in the No. 4 CB are as follows:

The No. 4 CB was in operation as follows:
2002 – 5,949 hours (2,3 & 4Q's), 2003 – 8,302 hours, 2004 – 8,425 hours, 2005 – 8,323 hours

The No. 4 CB was used to burn NCG/SOG gases as follows:
2002 – 1,120 hours (18.8% of the time), 2003 – 1,286 hours (15.5% of the time),
2004 – 1,341 hours (15.9% of the time), 2005 – 1,007 hours (12.1% of the time),

Note – The old TRS incinerator was used until April 2002.

It is unclear why this issue is being re-visited as part of this permitting action when these projects do not affect the manner in which NCG/SOG/DNCG gases are burned.

9. Based on the exceptions listed in the PSD Report, Section 2.3.1., Past Actual Emissions, have you submitted a correction to the 2004 and 2005 AORs?

This is actively being worked on and updates will be sent to DEP by September 29, 2006. Based on the updates to the AOR, updates have been made to Tables 2-1, 2-3, and 3-3 of the No. 4 CB PSD Application. The changes are minor in nature and do not affect any conclusions stated in the PSD report. The revised tables are included in Attachment L.

10. The Bark Hog project used a heating value for wet as-fired bark of 4500 Btu/lb. Yet for this project, the value of 4750 Btu/lb, wet and as-fired is being used. The permitted capacity of Btu/hr heat input to the No. 4 CB was limited to 512.7 MMBtu/hr, based on "57 tons per hour carbonaceous fuel (bark/wood chips) with an average heating value of 4500 Btu/lb on a wet, as-fired basis". In this application, the requested heat input is 564 MMBtu/hr based on "59.4 TPH tons per hour carbonaceous fuel (bark/wood chips) with an average heating value of 4750 Btu/lb on a wet, as-fired basis". Please explain why you used a different heating value for the same material. Also, resubmit corrected pages as appropriate.

The 4750 btu/lb value most closely represents the heating value of bark/wood being burned in the No. 4 CB. The 4750 btu/lb value is the result of testing in 2003/2004 and is used in the mill for heat input calculations. This value is currently being used to calculate heat inputs during compliance stack testing and during daily operations.

11. According to the application, the current permitted maximum heat input rate to the No. 4 CB is 512.7 MMBtu/hour based on a 24-hour average. Based on a wood/bark heating value of 4750, this is equivalent to a maximum of 54 TPH and 1296 TPD of wood/bark firing. The application requests a maximum annual heat input rate of *4,042,127 MMBtu during any* consecutive 12 months. The proposed physical changes (upgraded bark/wood delivery system, new air swept bark/wood feeders, new OFA system and modified combustion air supply, modified under fire air distribution, upgraded ash removal system, etc.) will allow the existing No. 4 CB to achieve the above maximum heat input rates and wood/bark firing rates. Is this accurate?

The maximum annual heat input rate is correct as requested. The No. 4 CB can already achieve the maximum hourly and 24-hour heat input rates, as demonstrated by historic steam rate records, based on firing a combination of bark/wood and fuel oil. As described in the application, the proposed changes will only allow more bark/wood to be burned on a short-term and annual basis, thereby reducing the need for fuel oil.

12. For CO, NOx, SO_2, and VOC emissions: provide any emissions test data available for the No. 4 CB; and, provide any emission test data available for other G-P boilers similar to the No. 4 CB at the Palatka Mill.

The Palatka Mill has performed some limited stack testing for NO_x and SO_2. A summary of the data is in Attachment B. We have not collected any data for CO or VOC emissions.

GP owns two combination boilers other than the one at the Palatka Mill that are similar in design in that they use a traveling stoker grate to burn "hog" fuel in addition to burning supplemental fossil fuel. One of these boilers is located at GP's Camas, Washington Mill and the other boiler is located at GP's Monticello, Mississippi Mill. However, both of these boilers burn natural gas as the supplemental fuel in addition to hog fuel, and not No. 6 fuel oil as is the case for the boiler at the Palatka Mill. For this reason, GP does not have any emissions test data from other boilers that can be compared to the unit at the Palatka Mill.

13. See Attachment GP-EU1-I1, which is a process flow diagram for the No. 4 CB.

a. This chart shows ash from the new mechanical dust collector being directed back to the NO. 4 CB and not the ash sluice tanks. Please explain.

Ash from the dust collectors and precipitators will be sluiced. An updated Process Flow Diagram is included in Attachment C.

b. This chart shows the exhaust from the No. 4 CB directed to the new mechanical dust collector and then being split between the existing ESP for the No. 4 CB and the existing ESP for the No. 5 PB. The application later indicates that the ESPs for the No. 4 CB and the No. 5 PB will be refurbished the ESP for the No. 5 PB may be used as the 4th, 5th and 6th fields for the exhaust from the No. 4 CB. If this happens, a new ESP will be installed for the No. 5 PB. In other words, the exhaust streams will never mix and there will only be one stack. Is this accurate? Provide additional details of the proposed configuration, cost of the proposed ESP work for the No. 4 CB, cost of the proposed ESP work for the No. 5 PB (including new field), cost of the connecting ductwork, and the cost of a proposed new ESP for the No. 5 PB.

The exhaust gases from the No. 5 PB will never mix with the exhaust gases from the No. 4 CB. While the exact configuration has not been finalized it is currently thought that the No. 5 PB stack would be used for the No.5 PB and the existing No. 4 CB stack will be used for the No. 4 CB. The appropriate duct work would be installed to make this happen.

It is still possible that a new stack will be installed with a new precipitator for the No. 5 PB. In that case the two existing precipitators and stacks would be used for the No. 4 CB. Specific cost data is not available at this time because exact arrangement for the No. 4 CB has not been finalized. The plans will be finalized during detailed design engineering. While final funding approval has not yet occurred we have estimated that over $2.5 million will be spent on the No. 4 CB ESP.

c. The Department is aware the G-P has filed a separate minor source air construction permit with the NED Office to install a new field on the No. 5 PB. The system is being designed for a much larger flue gas flow rate than is needed for the No. 5 PB. Has G-P made the decision to use the refurbished ESP for the No. 5 PB to control emissions from the No. 4 CB? Isn't this project related to the PSD application for the No. 4 CB? Please explain.

As stated in the application for the No. 5 PB ESP upgrade, the purpose of the upgrade is primarily to improve reliability of the ESP to meet the PM emission limits for the No. 5 PB at various operating loads in the event that the No. 4 CB upgrade project is not funded. This project is not related to the No. 4 CB project in any way. The design flue gas flow rate shown in the application of 455,000 actual cubic feet per minute (acfm) is an error and should be shown as 230,000 acfm (the original design value that is not being changed). An updated table (GP-EU1-I3) from the No. 5 PB precipitator construction permit application is included in Attachment D. This updated table is being sent to the DEP Jacksonville Air office as well.

The new field in the precipitator for the No. 5 PB is designed to offer better collection efficiency on that unit under current operating conditions, and to provide operational flexibility in the case of equipment downtime on one field.

A final decision on how the No. 4 CB ESP field design will be augmented has not been made. The use of the No. 5 PB ESP in series, and following the No. 4 CB ESP is just one of the options being considered. Other options include increasing the size of the chambers or adding just one new chamber.

14. See Attachment GP-EU1-I3, which provides control equipment details for the No. 4 CB.

- **Details for the new mechanical dust collector indicate a maximum inlet flow rate of 280,000 acfm @ 700° F.**
- **Details for the refurbished ESP for the No. 4 CB indicate a maximum inlet flow rate of 455,000 acfm @ 325° F.**

a. Is additional air being provided to cool the exhaust prior to the ESP?

As discussed in our response to Question 13c, the correct design air flow for the ESP is 230,000 acfm. No cooling air or dilution air is provided prior to the ESP.

b. Identify the dscfm of exhaust from the NO. 4 CB, the dscfm of cooling air, and the total dscfm to the ESP.

The dscfm of exhaust from the NO. 4 CB is shown on page 17 of the emissions unit section of the application form – 135,400 dscfm @ 10% O_2. The typical oxygen content of the gas stream is 5%, which would result in an exhaust flow rate of 93,088 dscfm.

c. What is the design temperature for the ESP?

The actual design temperature for the ESP is 450°F. Attachment GP-EU1-I3 of the application form has been updated – see Attachment E.

d. Are new fans being installed to achieve this cooling and exhaust rate?

No. See answer to 14.a.

15. Why weren't past actual PM emissions simply based on previous stack test data? Does the boiler typically fire oil with wood/bark? At what rate? Are assumed control efficiencies reasonable based on the existing cyclone/ESP control system installed for this unit?

As described on page 2-5 of the PSD Report, actual stack tests were used to estimate past actual PM emissions. Since the stack tests allowed the development of emissions due to wood/bark and No. 6 fuel oil individually (see Table 5-4), these factors were applied to the annual fuel usage amounts for each individual fuel.

Currently, the boiler typically does fire some oil with wood/bark. Generally, about 400-600 gal/hr oil is fired with the maximum amount of wood that can be fired. As described in the application, the purpose of the proposed project is to increase the amount of wood/bark that can be fired and to decrease the fuel oil firing.

The assumed control efficiency is reasonable based on some test work on the inlet to the precipitator that indicates greater than 95% control efficiency for the existing No. 4 CB ESP. However, please note that past actual PM emissions from the No. 4 CB were not based on control efficiency of the ESP but rather the emission factors described in Table 5-4 of the PSD Report.

16. The application indicates that the current PM standard is 0.3 lb/MMBtu and requests a BACT limit of 0.04 lb/MMBtu. NESHAP DDDDD provisions establish a PM standard of 0.025 lb/MMBtu for new solid fuel-fired boilers. Table 5-1 of the application lists the PM/PM_{10} BACT determination for 34 recent projects for biomass-fired boilers. Of these, 17 projects have BACT determinations of 0.03 lb/MMBtu or less. Explain why the additional improvements described for the ESP(s) would not be able to achieve such a level of emissions for the No. 4 CB.

The No. 4 CB is not a new boiler, nor does it have new control equipment. Upgrades are being proposed to improve both combustion and control efficiency. However, an existing boiler cannot be expected to meet the emission levels of a completely new, modern boiler with a new ESP. New boilers have much greater furnace volumes to maximize combustion efficiency, minimize unburned carbon, and minimize the heat lost out the stack. The furnace volume of the No. 4 CB cannot be increased at this point in time, so there are limitations on what can be done to improve performance. Likewise, the existing ESP can only be improved to the extent possible based on the existing design and configuration. It cannot be modified to operate like a new ESP. That would require completely replacing the ESP.

The NESHAP DDDDD establishes a PM limit for *existing* boilers of 0.07 lb/MMBtu. The proposed BACT limit of 0.04 lb/MMBtu is closer to the limit for new boilers than it is to the limit for existing boilers. Since GP is proposing a not-to-exceed limit of 0.04 lb/MMBtu, actual PM emissions from the boiler will need to be lower in actual operation in order to maintain a margin of compliance..

17. The application indicates that new low-NOx burners (LNBs) will be installed to fire No. 6 fuel oil (2.35% sulfur content, by weight, max.). These burners will replace the same number of existing oil burners, will have the same heat input rate, will achieve a NOx emission standard of 0.27 lb/MMBtu, and will be restricted to firing no more than 5,100,000 gallons during any consecutive 12 months. The application also indicates that there are 6 oil guns. How many total oil burners are there? What is the generally acceptable range of NOx emissions for a burner to be considered a "low-NOx" burner? Provide the vendor specifications for both the CO and NOx emissions from the proposed new burners. Please explain the use of the "0.164" factor when estimating SO_2 emissions from oil firing. Is this a reasonable estimate of SO_2 emission from oil firing?

In the application, "oil gun" is synonymous with "oil burner". Low-NO_x burners for No. 6 fuel oil generally provide only a small amount of NO_x reduction due to the nature of the No. 6 fuel oil and the fuel bound nitrogen. Generally a 10%-15% reduction in NO_x from existing levels would classify the burner as low-NO_x.

We do not have a vendor specification for emissions from a low-NOx burner while burning No. 6 fuel oil. The proposed emission limit for NO_x is based on discussions with the vendor and an estimated 15% reduction from the uncontrolled emission rate of 0.31 lb/MMBtu.

The "0.164" factor was actually required by the Department in the previous permitting of the No. 4 CB. It is based on a stoichiometric calculation of the sulfur in the fuel converting to SO_2:

$$8.2 \text{ lbs/gal} \times (\%S/100) \text{ lb S/lb oil} * 64 \text{ lb } SO_2\text{/lb-mole} \div 32 \text{ lb S/lb-mole} \times \text{lb mole } SO_2\text{/lb-mole S} =$$

$$0.164 * \%S \text{ lb } SO_2\text{/ gal oil}$$

where: %S is the percent sulfur in the fuel,

This equation may overestimate the actual SO_2 emitted since some sulfur will be converted to SO_3 or SO_4 in the stack and will not exit the stack as SO_2.

It is unclear why this issue is being re-visited as part of this permitting action when it has been addressed as part of prior permitting actions.

18. Describe the new equipment, controls, and improvements to the over fire air (OFA) system for the No. 4 CB. Has (or will) computational fluid dynamic modeling be conducted to aid in the design of the OFA? Provide any vendor specifications available regarding emission levels before and after installation of the new OFA.

If needed, Computational Fluid Dynamic (CFD) modeling will be conducted during the design phase of this project depending upon the vendor selected and that vendor's design needs. More refined emission level estimates would be available as a result of this modeling.

Although final engineering has not been performed, the system would generally consist of the following components: new over fire air nozzles; dampers with automatic drives; ductwork; pressure, temperature and air flow monitors and transmitters; new fuel distributors; and O&M manuals. One vendor has guaranteed a NO_x emission level of 0.24 lb/MMBtu, while another has guaranteed 0.25 lb/MMBtu following the installation of the new OFA system.

19. Does the No. 4 CB currently have flue gas recirculation (FGR)? What is the maximum designed percent of FGR? Does the boiler operate at this rate? When was it installed?

This unit is not equipped with an FGR system.

20. As stated in the application, SNCR for several Florida biomass-fired boilers have achieved levels of up to 50% NOx reduction. Provide a revised cost effectiveness analysis assuming this level of control. Provide details for this specific boiler that causes problems related to an SNCR system and high control efficiencies

Due to the existing boiler design and associated constraints, the SNCR vendor (FuelTech) will not guarantee a NOx reduction of greater than 35% for bark/oil and 25% for oil alone. The constraints that affect the vendor guarantee include: combustion byproducts, upper furnace flue gas temperature, flue gas velocity and residence time available to the SNCR process, furnace access for reagent distribution purposes, flue gas temperature at the outlet of the air preheater, and the amount of ammonia slip that can be tolerated.

21. Page 3-12 of the application states that NSPS Subpart Db could apply to the project to modify an oil and wood-fired boiler if there was an hourly increase in emissions. The conclusion is that this subpart does not apply because PM emissions will actually decrease for this unit. Provide a similar discussion for SO_2 and NOx emissions, which are also regulated by this subpart. Please correlate the discussion with that provided on Page 3-13 regarding SO_2 and NOx emissions.

As stated in the application, the project includes replacing the existing No. 6 fuel oil burners with oil burners of the same number and capacity. As such, the fuel oil burning potential of the boiler is not increasing. Therefore, SO_2 emissions will not increase on an hourly basis for fuel oil firing. Since hourly SO_2 emissions due to fuel oil firing will not increase, and there is no SO_2 emission standard in the NSPS for wood firing, the NSPS will not be triggered for SO_2.

Likewise, for NO_x, the fuel oil burning potential of the boiler is not increasing, and the low-NO_x burners will result in a reduction in maximum hourly NO_x emissions due to fuel oil firing. Since hourly NO_x emissions due to fuel oil firing will not increase, and there is no NO_x emission standard in the NSPS for wood firing, the NSPS will not be triggered for NO_x.

22. Is the existing No. 4 Power Boiler currently shutdown? What is the date of last operation for this unit? Is this unit currently able to operate in its current condition? When will construction begin on the proposed PSD project?

The No. 4 PB is shutdown. It last operated in September 2003. The unit could not operate in its current condition. The shutdown of this unit is documented in Section 2.2 of the PSD Report. Construction on the proposed PSD Project should commence in late March to early April 2007.

23. In the section labeled "PSD Report", specifically page 2-7, next-to-last paragraph, you indicated that the No. 5 PB's modified ESP "may" be used by the No. 4 CB's operation for additional control of particulate emissions. Based on this, please respond to the following issues:

a. Please describe what "may" means.

"May" means plans are not yet final. In the event that the CB Upgrade Project is funded, the No. 5 PB ESP may be used as a final PM control device in conjunction with (in series or in parallel) the existing No. 4 CB ESP. Also note that we are not stating that both the No. 4 CB and the No. 5 PB will be controlled by the existing No. 5 PB ESP. In fact the stack gases from the individual boilers will not be combined in any fashion.

If the No. 5 PB ESP is used as a control device for No. 4 CB, then current plans call for the No. 5 PB to have a new ESP installed to control its emissions (see pg. 1-1 of PSD Report). This was addressed in our response to Question 13 above.

b. Are you planning to use the No. 5 PB's modified ESP to control particulate emissions from the No. 4 CB's operation on a permanent basis? If Not, please explain.

If the No. 4 CB stack gases are routed to the existing No. 5 PB ESP, it will be on a permanent basis. We are currently exploring whether the existing ESPs would be utilized in parallel or in series once they are servicing the No. 4 CB.

c. Which stack will be used on a permanent basis...the No. 4 CB's or the No. 5 PB's....when the No. 5 PB's modified ESP is being utilized?

Both stacks will be used on a permanent basis. It is expected that the No. 4 CB stack will continue to service the No. 4 CB and the No. 5 PB stack will continue to service the No. 5 PB. As discussed in several answers above and in the application, the configuration has not yet been finalized.

d. Since the No. 5 PB and its mass emissions will be impacted by the No. 4 CB project, have the emissions of all affected pollutants been included in the modeling for the No. 4 CB project, which includes the Nos. 4 RB and LK projects? Did you assess the potential impact of all of the pollutant emissions exiting the No. 5 PB's modified ESP and its associated stack?

The No. 5 PB operation or emissions are not being impacted in any manner except that the No. 5 PB ESP may be used as additional fields to augment the No. 4 CB ESP. The No. 5 PB ESP would be upgraded in the event that the No. 4 CB Upgrade project is funded. As stated in our response to Questions 13 and 23 b above, we are stilling exploring the exact configuration of the flows through the ESPs.

We expect that this would only have the effect of lowering PM emissions from the No. 5 PB. The No. 5 PB, itself, will not be modified in any way as part of the proposed project.

e. What is the resultant flue gas volumetric flow rate in "dscfm @ 10% O_2" when the No. 5 PB's modified ESP is being utilized by the No. 4 CB's operation?

Since the flow rate is dictated by the No. 4 CB (boiler), and not the ESP (regardless of which ESP is used), the flow rate shown on page 17 of the application for the No. 4 CB, 278,400 acfm, is valid for this scenario as well. The gas flow rate is 135,000 dscfm @ 10% O_2.

f. List and describe all of the "methods of operation" for which the No. 5 PB's modified ESP will be used by the NO. 4 CB's operation, and this listing should include all of the fuels (100% fuel oil to percentages of fuel oil and bark) used by the No. 5 PB and the No. 4 CB.

This question implies that two boilers will be routed to a single ESP. This will not be the case. Under the scenarios described above, No. 4 CB and No. 5 PB will continue to have separate, dedicated ESPs.

g. Regarding the No. 5 PB's modified ESP as an extended control device of the No. 4 CB's operation, what is the expected control efficiency for each pollutant? Provide all assumptions and calculations.

The ESP will only control PM emissions (and therefore metals and sulfuric acid mist). For the scenario where the No. 5 PB ESP acts as the second "3-field chamber" for the No. 4 CB, the PM control efficiency is difficult to determine, as much of the PM will have been removed in the first 3-field chamber (existing No. 4 CB ESP). Since the exact configuration of the flows through the ESPs has not yet been determined, we do not have estimates for each pollutant.

h. Will the pollutant emissions of the No. 5 PB's modified ESP increase due to this project?

No – that is not expected. We expect lower emissions. If a new ESP is installed for the No. 5 PB, more current technology would dictate that the unit perform, at or above, the efficiency of the existing ESP. See responses a.-f. above. We are not modifying the No. 5 PB ESP as part of this project. When exhaust gases from the No. 4 CB pass through the existing No. 5 PB ESP the discharge PM will have to meet the limit proposed in this application – 0.04 lbs/MMBTU.

i. Will the inlet loading to the No. 5 PB's modified ESP increase due to this project?

This depends on the exact configuration of the revised ducting that will be used to direct flows to the ESP's. As stated previously, the No. 5 PB ESP could act as the second "3-field chamber" (in series) behind the No. 4 CB ESP's existing "3-field chamber". In this mode the inlet loading to the No. 5 PB ESP would be lower. If the two ESPs are operated in parallel, the inlet loading (in gr/dscf) to the No. 5 PB ESP would be expected to increase. In either case the resulting stack discharge would still meet the PM limits stated in this application.

j. Will there be an increase in the flue gas volumetric flow rate through the No. 5 PB's modified ESP due to this project? If so, please provide the assumptions and calculations for the potential pollutant emissions due to this increase in flow rate.

As described above this depends on the exact configuration of the revised ducting that will be used to direct flows to the ESPs. As stated previously, the No. 5 PB ESP could act as the second "3-field chamber" (in series) behind the No. 4 CB ESPs existing "3-field chamber". In this mode the flue gas volumetric flow rate would be the higher rate of the No. 4 CB.

If the two ESPs are operated in parallel, the flue gas volumetric flow rate to the No. 5 PB ESP would be expected to decrease.

In either case the resulting stack discharge would still meet the PM limits stated in this application.

k. For the No. 5 PB, what is the volumetric flow rate of the modified ESP in "dscfm @ 10%O_2"? Based on the RAI response letter to the Northeast District dated June 29, 2006, regarding an application to modify the No. 5 PB's existing ESP, the design flow rate for the No. 5 PB's modified ESP was stated as 455,000 acfm. Since the original design flow rate was 231,500 acfm, and your response in Response #3 was that there will be no change to the existing ESP's fans, ducts, etc., then please explain how the modified ESP's flow rate will be 455,000 acfm without some fan and/or physical modification? Please provide any assumptions and calculations.

As stated in our answers to Questions 13c and 14a, the 455,000 acfm value is incorrect. When utilizing the No. 5 PB ESP for the No. 4 CB emissions, the flow rate will be that of the No. 4 CB, 135,400 dscfm @ 10% O_2, as shown in the application form for the No. 4 CB. The original design flow rate for the No. 5 ESP was 230,000 acfm. This has not changed.

l. Since the No. 4 CB's TRS allowable limit is 5 ppmvd @ 10% O_2, the current potential mass emissions of 3.6 lbs/hr and 15.7 TPY are based on a volumetric flow rate of 135,400 dscfm. Unless the No. 5 PB's volumetric flow rate, in "dscfm @ 10% O_2", is the same as the existing No. 4 CB's dscfm flow rate, then the potential mass emissions of TRS will be increased when utilizing the No. 5 PB's modified ESP and appears to implicate that the net TRS mass emissions will be greater than significant and, therefore, subject to PSD NSR preconstruction review and BACT. If so, please submit the appropriate material and determination related to this.

The utilization of the No. 5 PB ESP has nothing to do with the allowable TRS emission from No. 4 CB. TRS is controlled by combustion and is not controlled by the ESP. The allowable emissions are based on the actual dscfm from the No. 4 CB.

m. In the PCP project for the burning of SOGs, NCGs and DNCGs, were the resultant SO_2 emissions evaluated exiting the Thermal Oxidizer and its backup, the No. 4 CB? Based on the current proposal, this evaluation should be conducted if the No. 5 PB's modified ESP is going to be utilized by the No. 4 CB's operations and SOGs, NCGs and DNCGs are being incinerated in the No. 4 CB. If this was Not done, please do so to provide reasonable assurance that there is no NAAQS Nor increment violations.

Yes, both cases were evaluated. As far as impacts on modeling results, the previous modeling is considered adequate since the No. 4 CB and No. 5 PB stacks are located adjacent to each other (within 25 feet), and both have the same stack height and diameter (*i.e.*, the stacks are identical).

n. It appears that the No. 5 PB's ESP modification and the recent application submittal for modifications to the Nos. 4 CB, RB and LK are related, i.e., the No. 5 PB's modified ESP will become a particulate control device for the No. 4 CB's operation. As such, why wasn't the No. 5 PB's ESP modification and any appropriate changes, including impacts, modeling and potentially BACT, included in this project?

This question was asked and answered in our response to Question 13c. As such, it is unclear why this question is being asked a second time. As stated previously, the No. 5 PB ESP "may" be used as a second "three field chamber" for the No. 4 CB. This decision has not been finalized. In this case, emissions from the No. 5 PB will not be affected, except that its new ESP should be more efficient with lower PM emissions.

24. In the netting table, why did you not include any past and future TRS mass emissions from the No. 4 CB, since it is the back-up control device for SOGs and NCGs and the primary control device for DNCGs, and it has an allowable emissions limit of 5 ppmvd @ 10% O_2? It should at least include the "20% utilization factor" requested and depicted in Attachment GP-EU1-F1.8. Was the No. 4 CB used during CY 2004 and 2005 for the incineration of these gases? Provide the dates and amount of time it was utilized for this purpose during these years and make the calculations and appropriate adjustments to the netting table, Table 1, Past Actuals. Also, see Issue No. 5, above.

The exclusion of the emissions from No. 4 CB due to incineration of TRS/HAP gases was explained at length on pages 2-7 and 2-8 of the PSD Report. The incineration of these gases will not be affected by the proposed No. 4 CB project. The burning of NCG/SOG gases in the No. 4 CB is addressed in our response to Question 8.

25. In the application, Section H. Continuous Monitor Information, there was no pages completed, yet the requirements for continuous emissions monitoring of TRS emissions pursuant to Rule 62-296.404(3)(f) and (5)(c), F.A.C., are applicable. Have you installed the devices to continuously monitor temperature at the point of combustion and oxygen pursuant to the requirements? If not, please explain. If so, please complete the appropriate application pages and submit.

Pursuant to 62.296404(3)(a), NCGs from the digesters, MEE system, and condensate stripper are to be "collected and incinerated in a lime kiln or calciner…or kraft recovery furnace…, or a combustion device." Note that the term incineration is used to describe the process of combustion

rather than referencing combustion in a particular device. Section 404(3)(f) essentially defines "other combustion devices" as power boilers, carbonaceous fuel burning equipment and incinerators. In our case, these gases are collected and incinerated in the Combination Boiler, a carbonaceous fuel burning device. Because the Department defined power boilers and carbonaceous fuel burning equipment separately from an incinerator, the requirement to install equipment to monitor temperature in 296.404(5)(c) does not apply. There is also no requirement that the Combination Boiler be equipped with a TRS CEMS because the control technology employed is incineration (see 296.404(5)(a)).

As discussed in our response to Question 5, the Cluster Rule requirements were satisfied by demonstrating that the TRS gases will experience a 1,200°F temperature for at least 0.5 second.

As is the case with so many other questions in this document, this question has no relevance to the application at hand. The monitoring requirements were all addressed, and permitted, as part of our past Cluster Rule compliance projects. As discussed in detail in our application, the proposed project for the No. 4 CB will not affect the manner in which NCG/SOG/DNCG gases are burned in the boiler or the emissions resulting from such burning.

26. In Attachment GP-EU1-I3, Detailed Description of Control Equipment, specifically for the No. 5 PB's ESP, the control efficiency is listed as 99.5% for particulate matter. Is this accurate? If not, please explain, correct and resubmit the document.

No the control efficiency value was updated in the RAI response on the No. 5 PB ESP Third Field project (Permit No. 1070005-036-AC). The updated design information table for the No. 5 PB is included in Attachment D.

27. Please identify any other emissions units/activities that will be affected upstream and downstream by the increase in production and steam output due to the proposed modification of the No. 4 CB. If any, please include in the analysis any increases in production and associated pollutant emissions, including any collateral emission changes and increases (NCG's TRS to SO_2, etc.) for these emissions units/activities.

Because there is no increase in heat input or steam output (production) there are no other emissions units or activities affected either upstream or downstream. The project does describe the increase in bark throughput with a coincidental reduction in oil consumption. The Bark Hog project (Permit No. 1070005-028-AC/PSD-FL-341) was originally part of the overall No. 4 CB upgrade project but, as you are aware, we were directed by the Department to break these into two separate projects. We were later directed by the Department to re-combine them, and also consider other non-related projects, as part of an overall NSR applicability analysis. The Bark Hog permit was issued on January 5, 2005.

As discussed in detail in numerous places in our application, the proposed project for the No. 4 CB will in no way affect the manner in which NCG/SOG/DNCG gases are burned.

No. 4 Lime Kiln (LK).

28. For the LK, provide the actual venturi scrubber pressure differential for each of the particulate matter emissions tests provided with the application (1995 – 2005).

The values are as follows:

1995 – 27", 1996 – 27", 1997 – 28", 1998- 28", 1999 – 28",
2000 – 28", 2001 - 28", 2002 – 28", 2003 – 28", 03/2004 – 27", 08/2004 – 26", 2005 – 26".

29. The proposed BACT emissions standards in Table E-7 do not reflect the proposed BACT standards in the DEP application form Nor the annual emissions used in the netting analysis. Please revise accordingly.

The revised Table E-7 is in Attachment F.

No. 4 Recovery Boiler (RB).

30. For the RB, the application proposes the following CO limits: 800 ppmvd @ 8% oxygen (3-hour average) and 400 ppmvd @ 8% oxygen (24-hour average). The application also reflects G-P's agreement to install a CO CEMS. Please verify the averaging periods.

As previously agreed upon with the Department in discussions surrounding PSD-FL-367, Georgia-Pacific intends to install a CO CEMS on the Recovery Boiler outlet stack. We are committed to meeting the limits proposed in the latest RB draft permit that was sent to GP on May 26, 2006, namely: a 30-day rolling average of 800 ppm at 8% O_2 for the first 180 days after initial certification of the CO CEMS; and a 30-day rolling average of 400 ppm at 8% O_2 following the initial 180-day period.

31. For the RB, provide a discussion on the fraction of PM_{10} emissions of the PM emissions. This appears different than previous submittals.

The factor used was 75% of PM emissions and is the same factor used in the November 2005 RB PSD application. This factor comes from AP-42, Table 10.2-3, for recovery boilers without a direct contact evaporator, but with an ESP. The table shows that 74.8% of controlled PM is less than or equal to 10 microns.

Nos. 4 LK, RB and Smelt Dissolving Tank.

32. For all applicable units, please verify that past actual emissions for TRS and SO_2 were based on CEMS data and not test data. Please revise the calculation pages and the netting table appropriately.

The LK and the RB both have CEMS for TRS. However, there is no continuous gas flow rate measurement on which to base a calculation of annual emissions. Therefore, the stack test data and the operating hours are considered most representative for the calculation of past actual emissions.

Miscellaneous.

33. Where is the No. 5 PB located on the facility plot plan?

On the facility plot plans included in the applications, the No. 5 Power Boiler is referred to as the No. 5 Combo Boiler. This is not correct and the plot plan has been revised. A mill plot plan is included in Attachment G and the No. 5 PB is highlighted.

The No. 5 PB is located in the powerhouse structure adjacent to, and due east of, the No. 4 Recovery Boiler building. Both the No. 5 PB and No. 4 CB are housed in the powerhouse building with the No. 5 PB on the north side and the No. 4 CB on the south side. The stacks for the boilers are located on the south side of the structure with the No. 5 PB stack being on the west side and the No. 4 CB stack on the east side.

34. Due to the recent changes made regarding the Primary Responsible Official and Authorized Representative at the Georgia-Pacific's Palatka Mill, please have Mr. Wahoske sign, date and submit a completed application's "Owner/Authorized Representative Statement" page for each of the submitted applications, one for the No. 4 CB and one for the combined LK and RB.

We will submit these, because it is not unduly burdensome to do so, but the request strikes us as unnecessary. Mr. Kennedy was the Mill Manager and Responsible Official at the time these applications were submitted, and it happens that Mr. Wahoske is now the Mill Manager and Primary Responsible Official going forward. Mr. Wahoske or one of his duly designated alternatives will sign all Title V submittals in the future, but we do not think it is necessary under the rules or otherwise to re-submit previously-submitted permit applications, or any other previously-submitted Title V documents, just because the Mill's Responsible Official has changed. The Company's certification of the previously-submitted application is still "good" even though the Mill Manager/Responsible Official has changed. We question whether such a change in Responsible Officials is a valid or legitimate basis to hold up permit processing via an RAI.

The requested forms are included in Attachment H.

35. The Department did not receive the results of the SO_2 air dispersion modeling mentioned on page 4-2 of the RB's and LK's application. This modeling should include not only mill-wide SO_2 emissions due to the mill operating at the projected highest short-term limits, but all applicable nearby sources, and should include predicted impacts in both the PSD Class I and Class II areas. This modeling is required by Rule 62-212.300(1), F.A.C.

A report answering this question is included in Attachment I. Note that the modeled emissions for RB SO2 included a 24-hour average of 100 ppm and a 3-hour average of 150 ppm. Also included on page 3 of the report are the results of the modeling of Recovery Boiler start-up emissions when No. 6 Fuel Oil is used as the start-up fuel. **The modeling shows that the Florida AAQS's for SO2 are being met during Recovery Boiler start-ups.**

Appropriate data files have been sent electronically to Mr. Cleve Holladay at DEP.

36. In Section 2.6.4 on page C-7 of the RB's and LK's application, the maximum receptor distance for the significant impact analyses is given as 4 km. Please provide the justification for this distance.

As stated at the top of page C-7, receptors used in the significant impact analysis extended out 4 km from the Mill. It is also stated on this page that predicted concentrations exceeding the significant impact level (SIL) for PM_{10} and NO_2 were all located within 2 km of the modeling origin. It is further stated on page C-8 that the significant impact distances for PM_{10} and NO_2 were 1.0 km and 0.8 km, respectively. Therefore, the maximum receptor distance of 4 km was more than adequate to capture the points of maximum impact due to the project.

37. If the responses to any of the Department's comments above change the pollutant emission rates or stack configurations, these changes should be evaluated by the appropriate air dispersion modeling and the results provided to the Department.

This was done to the extent necessary to respond to the Department's questions. See response to question 35.

38. Please provide a facility plot plan in AUTOCAD format, which shows the location of all stacks, buildings, fence lines and roads. This plot plan should have a scale and be in UTM coordinates.

The appropriate data files are being submitted electronically to the Department by Golder Associates. A hard copy of the facility plot plan showing the requested information and UTM coordinates is in Attachment J.

39. If any response to the above issues affect the application submittal, please correct and/or change the application to reflect the additional analyses and submit.

As needed, application updates and information are included in the attachments as indicated throughout this response report.

If you have any questions regarding this matter, please contact Myra Carpenter at 386-329-0918.

Sincerely,

Keith Wahoske

Keith W. Wahoske, Vice-President
Palatka Operations

cc: David Buff, P.E., Golder
T. Champion, T. Wyles, S. Matchett, Myra J. Carpenter, GP
Mr. Christopher Kirts, P.E. - FLDEP

LIST OF ATTACHMENTS

ATTACHMENT A (Q-5)

D. Buff letter to R. Felton-Smith – dated 6/30/04

ATTACHMENT B (Q-12)

No. 4 CB – Emissions data summary for NOx and SO2

ATTACHMENT C (Q-13)

Updated Process Flow Diagram – No. 4 CB – (GP-EU1-I1)

ATTACHMENT D (Q-13/26)

Updated No. 5 PB ESP data table (GP-EU1-I3)

ATTACHMENT E (Q-14)

Updated No. 4 CB ESP data table (GP-EU1-I3)

ATTACHMENT F (Q-29)

Summary of Proposed Selection of BACT for Lime Kiln

ATTACHMENT G (Q-33)

Revised Facility Plot Plan showing the No. 5 PB.

ATTACHMENT H (Q-34) -cb

Updated Application signature forms

ATTACHMENT I (Q-35)

Recovery Boiler SO2 Modeling Report

ATTACHMENT J (Q-36)

Facility Plot Plan – Showing boundaries and UTM
AutoCAD format sent electronically

ATTACHMENT K (Q-2)

Table 3-1 (11/14/01); GP-EU1-G8 a & b (10/29/03)

ATTACHMENT L (Q-9)

Updated Tables 2-1, 2-3, and 3-3 – No. 4 CB PSD

ATTACHMENT A (Q-5)

D. Buff letter to R. Felton-Smith – dated 6/30/04

Golder Associates Inc.

6241 NW 23rd Street, Suite 500
Gainesville, FL 32653-1500
Telephone (352) 336-5600
Fax (352) 336-6603

received
7/06/04

Golder Associates

June 30, 2004

0337567

Ms. Rita Felton-Smith
Florida Department of Environmental Protection
7825 Baymeadows Way, Suite B200
Jacksonville, FL 32256-7590

RE: MACT APPLICATION FOR BROWN STOCK WASHER AND OXYGEN DELIGNIFICATION SYSTEM
GEORGIA PACIFIC CORPORATION, PALATKA, FLORIDA
DEP FILE NO. 1070005-024-AC
RESPONSE TO SUPPLEMENTAL INFORMATION REQUEST

Dear Ms. Felton-Smith:

At Georgia-Pacific's (GP's) request, I am providing the supplemental information requested in your recent email.

Attached find an updated page 2-2 from the original air construction permit application. This corrected page now includes all the major equipment items GP is planning on installing.

Calculations documenting that the HVLC/LVHC NCG gases will be subject to a minimum of 1,200 deg. F for at least 0.5 seconds is provided below for both the No. 4 Combination Boiler and the No. 5 Power Boiler.

No. 4 Combination Boiler :

Furnace volume = 12,000 ft^3

Furnace temperature (based on Babcock and Wilcox design) = 2,200°F

Gas flow rate at stack (avg. from last two stack tests) = 107,100 dscfm @ 16% H_2O

Flow rate through furnace = 107,100 dscfm x (2,660°R ÷ 528°R) ÷ (1 – 0.16) = 642,260 acfm

Residence time of gases in furnace = 12,000 ft^3 ÷ 642,260 acfm x 60 sec/min = 1.1 sec

As shown, the calculated residence time of the gases in the furnace is greater than 0.5 second.

No. 5 Power Boiler :

Furnace volume = 9,600 ft^3

Furnace temperature (based on Babcock and Wilcox design) = 2,300°F

Gas flow rate at stack (avg. from last two stack tests) = 142,600 dscfm @ 11% H_2O

Flow rate through furnace = 142,600 dscfm x (2,760°R ÷ 528°R) ÷ (1 – 0.11) = 837,530 acfm

Residence time of gases in furnace = 9,600 ft^3 ÷ 837,530 acfm x 60 sec/min = 0.7 sec

Please feel free to contact me if you have any questions concerning this information. Attached is the professional engineer certification page to accompany this submittal.

Sincerely,

GOLDER ASSOCIATES INC.

David A. Buff

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

cc: M. Carpenter, GP
E. Jamro, GP
S. Matchett, GP

Y:\Projects\2003\0337567 Georgia Pacific\4\4.1\061604\L063004-567.doc

Brown Stock Washing System:
- Foam Tanks and Vacuum Tanks
- Best Management Practices (BMP) Tank
- Brown Stock Washers and Vacuum Pumps
- BSW Filtrate Tanks
- Knotters, Screens, and Knotters & Screens Feed Tanks
- Drainers
- Refiner Feed Tank
- Grit Washer
- Weak Black Liquor Tanks
- HVLC System Condensate Standpipe
- High Density Pulp Storage (existing)
- Reject Handling System

Oxygen Delignification System
- Reactor Blow Tank and Blow Tube Vent Condenser
- Reactor Vessels (1st and 2nd stages) (relocated/refurbished)
- Pump Standpipes
- White Liquor Oxidation System
- Washer Filtrate Tanks
- Oxygen Delignification Washer
- Chemical Mixers, MC pumps

Bleach Plant
- Pre-wash System (existing)

Black Liquor Filter
- Pressure Filter (existing, to be relocated)

A flow diagram of the existing BSW system at Palatka is presented in Figure 2-1. The future system flow diagram is shown in Figure 2-2. A plot plan of the proposed systems is presented in Attachment GP-FI-C2 of the application form.

2.2 BROWN STOCK WASHING SYSTEMS

The brown stock washing configuration will be based on the processing of various pulp grades. The three pulp grades manufactured at the Palatka Mill include RP, soft pine (SP), and hardwood (Hwd). RP is high Kappa softwood pulp, used for manufacture of natural Kraft paper. SP is low Kappa softwood pulp used for the manufacture of bleached pulp grades. Hwd is pulp also used for the manufacture of bleached pulp grades.

Pulp from the blow tanks will be sent through pressure knotters and/or pressure screens. These are enclosed devices which will be vented to the HVLC system. The pulp will then be sent through the

Professional Engineer Certification

1. Professional Engineer Name: **David A. Buff**
   Registration Number: **19011**
2. Professional Engineer Mailing Address...
   Organization/Firm: **Golder Associates Inc.****
   Street Address: **6241 NW 23rd Street, Suite 500**
   City: **Gainesville** State: **FL** Zip Code: **32653-1500**
3. Professional Engineer Telephone Numbers...
   Telephone: **(352) 336 - 5600** ext. Fax: **(352) 336 - 6603**
4. Professional Engineer Email Address: **dbuff@golder.com**
5. Professional Engineer Statement:

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

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

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

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

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

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

David A. Buff
Signature

6/30/04
Date

(seal)

* Attach any exception to certification statement.

** **Board of Professional Engineers Certificate of Authorization #00001670**

ATTACHMENT B (Q-12)

No. 4 CB – Emissions data summary for NOx and SO2

#4 Combination Boiler - SO2 and NOx Testing

October 25 to 27, 2005

	BARK TPH	OIL KPPH	DATE	START TIME	END TIME	average NOx ppm	NOx lbs/hr	NOx lbs/mmbtu calc.'d Test cond.	NOx lbs/mmbtu From EPA- emmis-factors	average SO2 ppm	SO2 Stack lbs
TEST 1	39.6	0.795	25-Oct-05	22:20	23:00	141.1	93.5	0.24	0.27	39.5	24
TEST 2	35.9	5.61	26-Oct-05	15:47	16:27	144.1	95.5	0.21	0.26	299.7	184
TEST 3	28	8.44	27-Oct-05	2:15	3:15	156.1	103.5	0.24	0.29	335.7	309
TEST 4	16.9	7.42	26-Oct-05	18:15	19:15	122.6	81.3	0.27	0.3	277.7	255
TEST 5	40.1	3.18	26-Oct-05	16:25	17:20	138.8	92.0	0.21	0.23	236.5	199
TEST 6	40.1	0.797	25-Oct-05	16:00	17:00	155.6	103.2	0.26	0.28	314.5	289
TEST 7	0	19.33	26-Oct-05	6:00	7:00	157.5	104.4	0.28	0.35	649.1	597
TEST 8	0	15.88	25-Oct-05	11:53	12:24	152.4	101.0	0.34	0.39	808.5	384
TEST 9	0	18.69	25-Oct-05	13:00	14:00	172.9	114.6	0.32	0.38	861.8	793

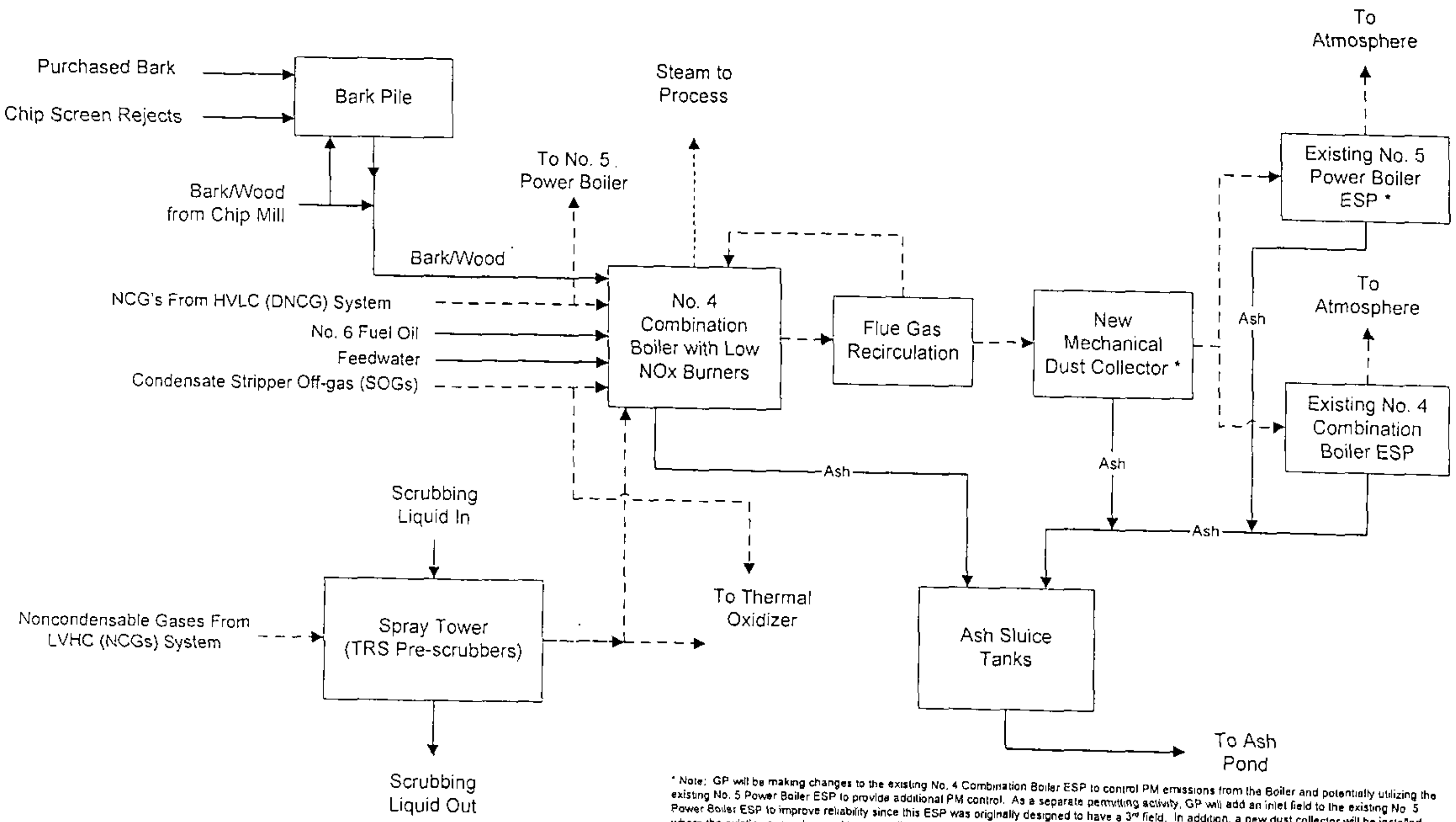
Notes
1. Sulfur dioxide emissions from Bark estimated at 0.025 lbs SO2 / mmbtu from bark; for GP Palatka bark = 4750 btu/lb
2. Sulfur in oil approximately 1.8% based on Sept.-05 tests.

\\PKSFHOME\esjamro$\STACK SAMPLING\#4CombBoiler -- #5PowerBoiler\2005\#4Comb-Boiler\PSD-permit tests\PSD-data-testing-No.4CB-10-2005-r2

ATTACHMENT C (Q-13)

Updated Process Flow Diagram – No. 4 CB – (GP-EU1-I1)

053-7627



* Note: GP will be making changes to the existing No. 4 Combination Boiler ESP to control PM emissions from the Boiler and potentially utilizing the existing No. 5 Power Boiler ESP to provide additional PM control. As a separate permitting activity, GP will add an inlet field to the existing No 5 Power Boiler ESP to improve reliability since this ESP was originally designed to have a 3rd field. In addition, a new dust collector will be installed where the existing secondary and tertiary collectors are and the primary dust collector will be abandoned. The existing hopper will either be bypassed with new ductwork or gutted and used to remove heavy particulate.

Attachment GP-EU1-I1
Process Flow Diagram
No. 4 Combination Boiler
Georgia-Pacific Palatka Mill

Process Flow Legend

Process Flow Legend	
Solid/Liquid	——→
Gas	- - - -→
Steam	·········→

Filename: 4.4 No. 4 CB/GP-EU1-I1_061306.VSD
Date: 09/18/06

Golder Associates

ATTACHMENT D (Q-13/26)

Updated No. 5 PB ESP data table (GP-EU1-I3)

ATTACHMENT D

CONTROL EQUIPMENT
NO. 5 POWER BOILER

The No. 5 Power Boiler is equipped with an electrostatic precipitator (ESP) for particulate control. Design information for the ESP is presented below.

Parameter	**Electrostatic Precipitator**
Manufacturer	Research Cottrell
No. of Fields	2
Gas Flowrate (acfm)	230,000
Primary Voltage (V)	0-600
Secondary Voltage (kVdc)	0-90
Primary Current (A)	0-150
Secondary Current (A)	0-1.0
Control Efficiency (%)	40% to 65%

Note: A third field will be installed in the existing chamber of the ESP Design data is not yet available for the third field; however, design will be consistent with design of the existing fields.

ATTACHMENT E (Q-14)

Updated No. 4 CB ESP data table (GP-EU1-I3)

ATTACHMENT E

CONTROL EQUIPMENT
NO. 4 COMBINATION BOILER

The No. 4 Combination Boiler is equipped with a new multiclone dust collector and an existing electrostatic precipitator (ESP) for particulate matter control. Design information for the control devices is presented below.

Parameter	**No. 4 Combination Boiler – Mechanical Dust Collector**
Manufacturer	To Be Determined
Inlet Gas Temp (°F)	700
Inlet Gas Flow (ACFM)	280,000
Pressure Drop (in. H_2O)	<3
Control Efficiency (%)	80-90

Parameter	**No. 4 Combination Boiler - Electrostatic Precipitator**
Manufacturer	Research Cottrell
Inlet Gas Temp (°F)	450
Gas Flow Rate (ACFM)	230,000
Primary Voltage (V)	0-600
Secondary Voltage (kVdc)	0-90
Primary Current (A)	0-150
Secondary Current (A)	0-1.0
Control Efficiency (%)	99.5

The existing No. 5 Power Boiler ESP may also be used for particulate matter control for the No. 4 Combination Boiler exhaust. Design information for the No. 5 Power Boiler ESP is presented below.

Parameter	**No. 5 Power Boiler Electrostatic Precipitator**
Manufacturer	Research Cottrell
Inlet Gas Temp (°F)	450
Gas Flowrate (acfm)	230,000
Primary Voltage (V)	0-600
Secondary Voltage (kVdc)	0-90
Primary Current (A)	0-150
Secondary Current (A)	0-1.0
Control Efficiency (%)	40-65

ATTACHMENT F (Q-29)

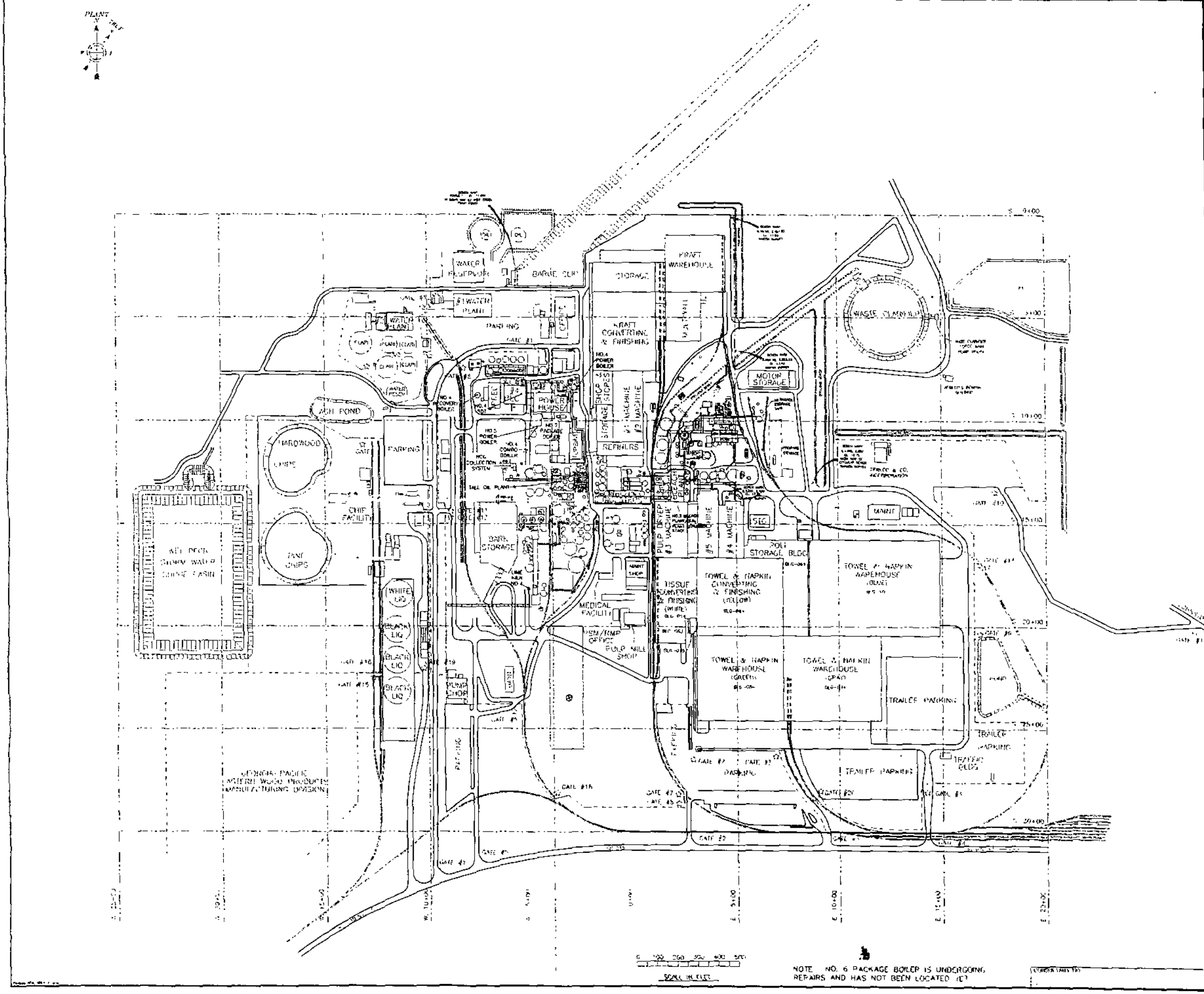
Summary of Proposed Selection of BACT for Lime Kiln

Table E-7. Summary of Proposed Selection of BACT for Lime Kiln

Pollutant	Control Technology	Ranking	Destruction Efficiency or Emission Rate
NO_x	Good Combustion	1	175 ppmvd at 10% O_2
PM/PM_{10}	Venturi Scrubber	3	0.064 gr/dscf at 10% O_2
VOC	Good Combustion/Proper Design and Operation	1	70 ppmvd at 10% O_2
CO	Good Combustion Practices	1	69 ppmvd at 10% O_2
SAM	No Controls	1	0.4 lbs/hr (1.8 tons/yr)

ATTACHMENT G (Q-33)

Revised Facility Plot Plan showing the No. 5 PB.



NOTE: NO. 6 PACKAGE BOILER IS UNDERGOING REPAIRS AND HAS NOT BEEN LOCATED YET

NOTES

LEGEND & INFORMATION

☆	GATE
┼┼┼┼	RAILROAD TRACK
— — —	FENCE

GATE #	DESCRIPTION
1	MAIN GATE
2	EAST GATE
3	OLD CONSTRUCTION GATE
4	TRUCK TRAFFIC GATE
5	CONSTRUCTION GATE
6	[illegible] GATE
7	R.R. GATE
8	PERIMETER GATE
9	PERIMETER GATE
10	CONSTRUCTION GATE
11	INNER MILL VEHICLE GATE
12	PERSONNEL GATE
13	PERSONNEL GATE
14	R.R. GATE
15	R.R. GATE
16	R.R. GATE
17	CONSTRUCTION GATE
18	R.R. GATE
19	[illegible] TRUCK SCALE
20	R.R. GATE

REV	DATE	DESCRIPTION
[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]

CROSS-REFERENCE NO.
C-290-8464-1-0105-001

SUPERSEDES

Georgia-Pacific

THE GROWTH COMPANY

PALATKA OPERATIONS

ATTACHMENT C
FACILITY PLOT PLAN, PALATKA MILL
053762\0100\[illegible]

DRAWN	[illegible]	SCALE	[illegible]
CHECKED		AFE NO.	
APPROVED		PROJ. NO.	
APPROVED		AREA	

G-P DRAWING NO.
290-8464ML-000-0009-000

ATTACHMENT H (Q-34)

Updated Application signature forms

APPLICATION INFORMATION

Owner/Authorized Representative Statement

Complete if applying for an air construction permit or an initial FESOP.

1. Owner/Authorized Representative Name:
   Mr. Keith W. Wahoske, Vice-President
2. Owner/Authorized Representative Mailing Address:
   Organization/Firm: **Georgia-Pacific Corporation**
   Street Address: **P.O. Box 919**
   City: **Palatka** State: **FL** Zip Code: **32178**
3. Owner/Authorized Representative Telephone Numbers:
   Telephone: **(386) 325-2001** ext. Fax: **(386) 328-0014**
4. Owner/Authorized Representative Email Address: **keith.wahoske@GAPAC.com**
5. Owner/Authorized Representative Statement:

I, the undersigned, am the owner or authorized representative of the facility addressed in this air permit application. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof and all other requirements identified in this application to which the facility is subject. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department, and I will promptly notify the department upon sale or legal transfer of the facility or any permitted emissions unit.

Keith Wahoske
Signature

9/22/2006
Date

Professional Engineer Certification

1. Professional Engineer Name: **David A. Buff**
   Registration Number: **19011**

2. Professional Engineer Mailing Address...
   Organization/Firm: **Golder Associates Inc.****
   Street Address: **6241 NW 23rd Street, Suite 500**
   City: **Gainesville** State: **FL** Zip Code: **32653**

3. Professional Engineer Telephone Numbers...
   Telephone: **(352) 336-5600** ext. **545** Fax: **(352) 336-6603**

4. Professional Engineer Email Address: **dbuff@golder.com**

5. Professional Engineer Statement:

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

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

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

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

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

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

David A. Buff
Signature

9/19/06
Date

(seal)

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* Attach any exception to certification statement.

** **Board of Professional Engineers Certificate of Authorization #00001670**

ATTACHMENT I (Q-35)

Recovery Boiler SO2 Modeling Report

ATTACHMENT I

As described in the prevention of significant deterioration (PSD) application, page 4-2, Georgia-Pacific Corporation (GP) has performed atmospheric dispersion modeling of higher short-term sulfur dioxide (SO_2) emissions from the No. 4 Recovery Boiler. For the 3-hour averaging time, SO_2 emissions from the No. 4 Recovery Boiler are based upon 150 parts per million by volume dry (ppmvd) at 8 percent oxygen (O_2). For the 24-hour averaging time, they are based upon 100 ppmvd at 8 percent O_2, and for the annual averaging time, they are based upon 12 ppmvd at 8 percent. The Palatka Mill SO_2 emission inventory used in the modeling analysis is presented in Tables I-1 and I-2. The emissions are consistent with recent permit applications submitted by GP, including the No. 4 Combination Boiler application and the Title V revision application for the Brown Stock Washing System. The Palatka Mill stack parameters are shown in Table I-3, and are the same as presented in the July 2006 permit application (Attachment C - Air Quality Analyses).

As shown in the tables, there are four emission scenarios. For each averaging time, Scenarios 2 and 4 have higher and equal total SO_2 emissions. However, Scenario 4 results in higher SO_2 emissions from the No. 5 Power Boiler as compared to the No. 4 Combination Boiler. Since both sources have the same stack height, but the No. 5 Power Boiler has a lower flue gas flow rate, the No. 5 Power Boiler will have a lower plume rise than the No. 4 Combination Boiler. Therefore, Scenario 4 was modeled as the worst-case condition.

SO_2 PSD Class II and AAQS Analyses

In May 2006, the Florida Department of Environmental Protection (FDEP) developed meteorological data from the Jacksonville International Airport for the years 2001 to 2005, and requested that applications use the data for future American Meteorological Society (AMS)/U.S. Environmental Protection Agency (EPA) Regulatory Model (AERMOD) modeling applications. The meteorological data were revised by FDEP to fill in missing upper air soundings in the original data set and provided to Golder Associates Inc. (Golder) in June 2006. The current air modeling analyses uses the revised meteorological data set to address compliance with the SO_2 Ambient Air Quality Standard (AAQS) and allowable PSD Class II increments in the vicinity of the Palatka Mill.

The modeling analysis was performed for the 3-hour, 24-hour, and annual averaging times, using GP's future maximum SO_2 emission rates. PSD baseline emissions were consistent with previous SO_2 modeling analysis (for example, the 2001-2002 modeling performed for the MACT I Compliance Pollution Control). All non-GP sources were modeled consistent with recent modeling analysis performed for Seminole Electric Cooperative, Inc. (SECI). The modeled configuration for SECI is consistent with the preliminary determination issued by FDEP, based on proposed improvements to be performed.

Summaries of the SO_2 AAQS and PSD Class II increment modeling analyses are presented in Tables I-4 and I-5. As shown in these tables, the maximum SO_2 concentrations predicted for the future Palatka Mill, together with background sources, complies with the SO_2 federal and Florida AAQS and with allowable PSD Class II increments.

SO_2 PSD Class I Increment Analysis

In order to provide a complete assessment of SO_2 PSD Class I increment consumption using the 2001-2003 California Puff (CALPUFF) meteorological data at the PSD Class I areas within 200 kilometers (km) of the Palatka Mill, air modeling analyses were performed for both the Okefenokee and Chassahowitzka National Wilderness Areas (NWAs). These meteorological data were made available and obtained from the FDEP in mid-April 2006. Previous modeling analyses were performed using the meteorological data for 1990, 1992, and 1996 as recommended by FDEP, EPA, and Federal Land Managers.

The modeling analysis was performed for the 3-hour, 24-hour, and annual averaging times, using GP's future maximum SO_2 emission rates. PSD baseline emissions were consistent with previous SO_2 modeling analysis (for example, the 2001-2002 modeling performed for the MACT I Compliance Pollution Control). All non-GP sources were modeled consistent with recent modeling analysis performed for SECI. The modeled configuration for SECI is consistent with the preliminary determination issued by FDEP, based on proposed improvements to be performed.

Summaries of the SO_2 PSD Class I increment modeling for the Chassahowitzka and Okefenokee NWAs using the CALPUFF meteorological data for 2001 to 2003 are presented in Tables I-6 and I-7, respectively. As shown in Table I-6, the maximum SO_2 concentrations predicted for the Palatka Mill, together with background sources, comply with the PSD Class I increments at the Okefenokee NWA.

As shown in Table I-7, the maximum SO_2 concentrations are predicted to exceed the allowable 24-hour increment at the Chassahowitzka NWA in 2002 and 2003 and also exceed the 3-hour PSD Class I increment in 2001, 2002, and 2003. The maximum predicted impact for each time period is presented in Table I-8, along with the contribution from the Palatka Mill's PSD increment consuming emissions. The Palatka Mill's contribution is predicted to be less than the PSD Class I significant impact levels for each 3-hour and 24-hour time period in which the allowable PSD Class I increments are exceeded. Therefore, the future Palatka Mill SO_2 emissions are not predicted to significantly impact any predicted exceedances at the Chassahowitzka NWA.

Recovery Boiler Startup Emissions

GP also investigated potential SO_2 impacts during a No. 4 Recovery Boiler startup event. During these events, No. 6 fuel oil is burned without any black liquor firing in the boiler. Under these conditions, the SO_2 emissions generated due to the fuel oil firing, are not absorbed into the furnace bed since the bed has not yet been established by burning black liquor. It is presumed under these conditions that all sulfur in the fuel oil exhausts out of the stack as SO_2.

GP reviewed past records of fuel oil firing during startup conditions, and found that the maximum No. 6 fuel oil burning rate would be 80 gallons per minute (gal/min) [4,800 gallons per hour (gal/hr)] for a 3-hour period, and 45 gal/min (2,700 gal/hr) for a 24-hour period. The potential SO_2 emissions are calculated as follows:

3-hr: 4,800 gal/hr x 8.2 pounds per gallon (lb/gal) x (0.0235 lb Sulfur (S)/lb oil)

x (mole SO_2/mole S) x (64 lb SO_2/mole SO_2)

x (mole S/32 lb S) = 1,849.9 lb/hr SO_2

24-hr: 2,700 gal/hr x 8.2 lb/gal x (0.0235 lb S/lb oil) x (mole SO_2/mole S)

x (64 lb SO_2/mole SO_2) x (mole S/32 lb S) = 1,040.6 lb/hr SO_2

Stack exhaust flow rate measurements were also obtained during a typical startup, and the testing indicated an average gas flow rate of 294,000 actual cubic feet per minute (acfm) and a stack temperature of 300 degrees Fahrenheit (°F).

The AAQS impacts were then re-evaluated with these stack parameters and emissions (PSD Class II and Class I increments were not evaluated since these are startup conditions). The results of the AAQS modeling are shown in Table I-9. As shown, all maximum impacts are below the AAQS.

TABLE I-1
MAXIMUM SHORT-TERM SO_2 EMISSIONS FOR GEORGIA-PACIFIC, PALATKA
2.35 PERCENT SULFUR CONTENT FUEL OIL AND MAXIMUM PULP PRODUCTION RATES
(REVISED JUNE 19, 2006)

Emission Unit	Unit ID	3-Hr Emissions (lb/hr)	3-Hr Emissions (g/s)	24-Hr Emissions (lb/hr)	24-Hr Emissions (g/s)
SCENARIO 1: LVHC NCGs/SOGs to THERMAL OXIDIZER HVLC DNCGs to NO. 4 COMBINATION BOILER					
Thermal Oxidizer w/LVHC	TO	31.3	3.95	31.3	3.95
No. 4 Recovery Boiler (150 ppm/100 ppm)	RB4	439.6	55.39	292.8	36.89
No. 4 Smelt Dissolving Tank	SDT4	7.7	0.97	7.7	0.97
No. 4 Lime Kiln	LK4	9.1	1.15	9.1	1.15
No. 5 Power Boiler	PB5	1,461.7	184.17	1,461.7	184.17
No. 7 Power Boiler	PB7	0.0	0.00	0.00	0.00
No. 4 Combination Boiler w/HVLC	CB4	1,158.1	145.92	1,142.6	143.97
TOTALS		3,107.5	391.5	2,945.2	371.1
SCENARIO 2: LVHC NCGs/SOGs to NO. 4 COMBINATION BOILER HVLC DNCGs to NO. 4 COMBINATION BOILER					
Thermal Oxidizer	TO	0.0	0.00	0.0	0.00
No. 4 Recovery Boiler (150 ppm/100 ppm)	RB4	439.6	55.39	292.8	36.89
No. 4 Smelt Dissolving Tank	SDT4	7.7	0.97	7.7	0.97
No. 4 Lime Kiln	LK4	9.1	1.15	9.1	1.15
No. 5 Power Boiler	PB5	1,461.7	184.17	1,461.7	184.17
No. 7 Power Boiler	PB7	0.0	0.00	0.00	0.00
No. 4 Combination Boiler w/ LVHC & HVLC	CB4	2,117.0	266.74	1,921.0	242.05
TOTALS		4,035.1	508.4	3,692.3	465.2
SCENARIO 3: LVHC NCGs/SOGs to THERMAL OXIDIZER HVLC DNCGs to NO. 5 POWER BOILER					
Thermal Oxidizer w/LVHC	TO	31.3	3.95	31.3	3.95
No. 4 Recovery Boiler (150 ppm/100 ppm)	RB4	439.6	55.39	292.8	36.89
No. 4 Smelt Dissolving Tank	SDT4	7.7	0.97	7.7	0.97
No. 4 Lime Kiln	LK4	9.1	1.15	9.1	1.15
No. 5 Power Boiler w/HVLC	PB5	1,544.3	194.58	1,528.8	192.63
No. 7 Power Boiler	PB7	0.0	0.00	0.00	0.00
No. 4 Combination Boiler	CB4	1,075.5	135.51	1,075.5	135.51
TOTALS		3,107.5	391.5	2,945.2	371.1
SCENARIO 4: LVHC NCGs/SOGs to NO. 4 COMBINATION BOILER HVLC DNCGs to NO. 5 POWER BOILER					
Thermal Oxidizer	TO	0.0	0.00	0.0	0.00
No. 4 Recovery Boiler (150 ppm/100 ppm)	RB4	439.6	55.39	292.8	36.89
No. 4 Smelt Dissolving Tank	SDT4	7.7	0.97	7.7	0.97
No. 4 Lime Kiln	LK4	9.1	1.15	9.1	1.15
No. 5 Power Boiler w/HVLC	PB5	1,544.3	194.58	1,528.8	192.63
No. 7 Power Boiler	PB7	0.0	0.00	0.0	0.00
No. 4 Combination Boiler w/ LVHC	CB4	2,034.4	256.33	1,854.3	233.64
TOTALS		4,035.1	508.4	3,692.7	465.3

Note: Emissions due to LVHC and HVLC NCGs based on pulp production rates of 118 TPH and 2,300 TPD ADUP.

TABLE I-2
MAXIMUM LONG-TERM SO_2 EMISSIONS FOR GEORGIA-PACIFIC, PALATKA
2.35 PERCENT SULFUR CONTENT FUEL OIL
(REVISED JUNE 19, 2006)

Emission Unit	Unit ID	Annual Emissions (TPY)	Annual Emissions (g/s)
SCENARIO 1: LVHC NCGs/SOGs to THERMAL OXIDIZER 100% HVLC DNCGs to NO. 4 COMBINATION BOILER 100%			
Thermal Oxidizer w/LVHC	TO	137.2	3.95
No. 4 Recovery Boiler	RB4	153.9	4.43
No. 4 Smelt Dissolving Tank	SDT4	33.7	0.97
No. 4 Lime Kiln	LK4	40.0	1.15
No. 5 Power Boiler	PB5	6,402.3	184.18
No. 7 Power Boiler	PB7	0.0	0.00
No. 4 Combination Boiler w/HVLC	CB4	1,260.1	36.25
TOTALS		8,027.2	230.9
SCENARIO 2: LVHC NCGs/SOGs to THERMAL OXIDIZER 80% LVHC NCGs/SOGs to NO. 4 COMBINATION BOILER 20% HVLC DNCGs to NO. 4 COMBINATION BOILER 100%			
Thermal Oxidizer w/LVHC	TO	109.8	3.16
No. 4 Recovery Boiler	RB4	153.9	4.43
No. 4 Smelt Dissolving Tank	SDT4	33.7	0.97
No. 4 Lime Kiln	LK4	40.0	1.15
No. 5 Power Boiler	PB5	6,402.3	184.18
No. 7 Power Boiler	PB7	0.0	0.00
No. 4 Combination Boiler w/ LVHC & HVLC	CB4	1,808.8	52.03
TOTALS		8,548.5	245.9
SCENARIO 3: LVHC NCGs/SOGs to THERMAL OXIDIZER 100% HVLC DNCGs to NO. 5 POWER BOILER 100%			
Thermal Oxidizer	TO	137.2	3.95
No. 4 Recovery Boiler	RB4	153.9	4.43
No. 4 Smelt Dissolving Tank	SDT4	33.7	0.97
No. 4 Lime Kiln	LK4	40.0	1.15
No. 5 Power Boiler w/HVLC	PB5	6,638.6	190.97
No. 7 Power Boiler	PB7	0.0	0.00
No. 4 Combination Boiler	CB4	982.8	28.27
TOTALS		7,986.2	229.7
SCENARIO 4: LVHC NCGs/SOGs to THERMAL OXIDIZER 80% LVHC NCGs/SOGs to NO. 4 COMBINATION BOILER 20% HVLC DNCGs to NO. 5 POWER BOILER 100%			
Thermal Oxidizer	TO	109.8	3.16
No 4 Recovery Boiler	RB4	153.9	4.43
No. 4 Smelt Dissolving Tank	SDT4	33.7	0.97
No. 4 Lime Kiln	LK4	40.0	1.15
No. 5 Power Boiler w/HVLC	PB5	6,638.6	190.97
No. 7 Power Boiler	PB7	0.0	0.00
No 4 Combination Boiler w/ LVHC	CB4	1,572.5	45.24
TOTALS		8,548.5	245.9

TABLE I-3
LOCATIONS AND STACK PARAMETERS FOR POINT SOURCES FOR NAAQS IMPACT ANALYSIS - GP PALATKA MILL

Model ID	Description	Stack Parameters									
		Source Location UTM		Stack Height		Stack Exit Temp		Stack Velocity		Stack Diameter	
		East (m)	North (m)	(ft)	(m)	F	K	(fps)	(m/s)	(ft)	(m)
TOX	Thermal Oxidizer	433996.65	3283401.08	250	76.2	160	344	18.0	5.49	3.6	1.10
RB4	# 4 Recovery Boiler	433897.37	3283458.89	230	70.1	425	491	65.9	20.08	12.0	3.66
SDT4	# 4 Smelt Dissolving Tanks	433949.76	3283498.51	206	62.8	180	355	34.0	10.35	5.0	1.52
LK4	# 4 Lime Kiln	434121.82	3283267.89	131	39.9	164	346.5	70.6	21.51	4.42	1.35
PB5	# 5 Power Boiler	433992.35	3283468.15	237	72.2	413	485	85.9	26.19	8.0	2.44
PB7	# 7 Package Boiler	434001.27	3283486.88	60	18.3	750	672	43.5	13.25	7.0	2.13
CB4	# 4 Combination Boiler	433997.52	3283471.42	237	72.2	466	514	92.3	28.14	8.0	2.44

TABLE 1-4
MAXIMUM PREDICTED SO_2 IMPACTS FOR COMPARISON TO THE FLORIDA AAQS

Averaging Time and Rank	Concentrations ($\mu g/m^3$)[a]			Receptor Location UTM Coordinates (m)		Time Period (YYMMDDHH)	Florida Ambient Air Quality Standards ($\mu g/m^3$)
	Total (c=a+b)	Modeled Source (a)	Background[a] (b)	East	North		
Highest Annual							
	27.1	21.1	6	434741	3283275	01123124	60
	25.4	19.4	6	434741	3283275	02123124	
	27.5	21.5	6	434629	3283191	03123124	
	26.0	20.0	6	434741	3283275	04123124	
	27.2	21.2	6	434704	3283247	05123124	
HSH 24-Hour							
	179	145	34	434704	3283247	01012024	260
	194	160	34	434554	3283135	02010724	
	190	156	34	434666	3283219	03121724	
	165	131	34	434704	3283247	04040224	
	181	147	34	434704	3283247	05122624	
HSH 3-Hour							
	637	509	128	434666	3283219	01011215	1,300
	642	514	128	434592	3283163	02022712	
	575	447	128	434666	3283219	03042618	
	640	512	128	434629	3283191	04041415	
	642	514	128	434629	3283191	05042718	

Note: YYMMDDHH = Year, Month, Day, Hour Ending.
HSH = Highest, second-highest
AAQS = Ambient Air Quality Standards

[a] Concentrations are based on highest concentrations predicted using AERMOD with five years of meteorological data from 2001 to 2005 of surface and upper air data from the National Weather Service station at Jacksonville International Airport as received from the FDEP

[b] Background concentrations are highest mean and HSH 24-and 3-hour concentrations, measured during 2004 and 2005 from Palatka monitoring station 12-107-1008.

TABLE I-5
MAXIMUM PREDICTED SO_2 IMPACTS FOR COMPARISON TO ALLOWABLE PSD CLASS II INCREMENTS

Averaging Time and Rank	Concentration ($\mu g/m^3$)	Receptor Location UTM Coordinates (m) East	Receptor Location UTM Coordinates (m) North	Time Period (YYMMDDHH)	Allowable PSD Class II Increment ($\mu g/m^3$)
Highest Annual					
	7.60	437,200	3,289,200	01123124	20
	7.30	437,100	3,289,100	02123124	
	6.70	440,500	3,289,700	03123124	
	5.40	440,600	3,289,400	04123124	
	6.40	437,300	3,289,600	05123124	
HSH 24-Hour					
	55.0	437,300	3,288,900	01072224	91
	58.8	437,200	3,289,200	02090624	
	59.5	437,300	3,289,700	03090124	
	51.7	437,100	3,290,000	04061324	
	59.7	437,400	3,289,700	05092524	
HSH 3-Hour					
	152.0	438,100	3,290,300	01072615	512
	147.9	437,838	3,290,126	02082915	
	144.5	437,600	3,289,900	03082215	
	149.5	440,338	3,289,319	04053012	
	149.5	437,557	3,289,548	05062215	

Note: YYMMDDHH = Year, Month, Day, Hour Ending.
HSH = Highest, second-highest
PSD = Prevention of Significant Deterioration

[a] Concentrations are based on highest concentrations predicted using AERMOD with 5 years of meteorological data from 2001 to 2005 of surface and upper air data from the National Weather Service station at Jacksonville International Airport as received from the FDEP.

TABLE I-6
MAXIMUM SO_2 IMPACTS PREDICTED FOR COMPARISON TO THE SO_2 PSD CLASS I INCREMENTS AT THE OKEFENOKEE NWA

Averaging Time/Rank	Maximum Concentration [a] (µg/m³)	Receptor Location LCC Coordinates (km) X	Receptor Location LCC Coordinates (km) Y	Time Period (YYMMDDHH)	PSD Class I Increment (µg/m³)
Annual					
Highest	0.00[b]	NA	NA	NA	2
	0.00	NA	NA	NA	
	0.00	NA	NA	NA	
24-Hour					
Second-highest	3.99	1,421.564	-921.107	01112924	5
	2.44	1,397.157	-930.757	02010924	
	2.16	1,397.157	-930.757	03111824	
3-Hour					
Second-highest	19.1	1,422.472	-926.620	01121221	25
	16.8	1,416.891	-912.442	02021006	
	24.4	1,419.983	-921.368	03112312	

Note: YYMMDDHH = Year, Month, Day, Hour Ending
LCC = Lambert Conic Conformal
NA = Not Applicable

[a] Based on the CALPUFF model using 3 years of CALMET meteorological data for 2001, 2002, and 2003, 4-km Florida domain.

[b] A "0.00" impact means that the predicted concentration was zero or less. The CALPUFF model does not print a negative concentration.

TABLE I-7
MAXIMUM SO_2 IMPACTS PREDICTED FOR COMPARISON TO THE SO_2 PSD CLASS I INCREMENTS AT THE CHASSAHOWITZKA NWA

Averaging Time/Rank	Maximum Concentration [a] (µg/m³)	Receptor Location LCC Coordinates (km) X	Receptor Location LCC Coordinates (km) Y	Time Period (YYMMDDHH)	PSD Class I Increment (µg/m³)
<u>Annual</u>					
Highest	0.05	1,411.565	-1,143.104	01123124	2
	0.00 [b]	NA	NA	NA	
	0.00	NA	NA	NA	
<u>24-Hour</u>					
Second-highest	4.91	1,411.565	-1,143.104	01112724	5
	5.85	1,402.723	-1,139.772	02122724	
	7.75	1,405.965	-1,139.257	03082724	
<u>3-Hour</u>					
Second-highest	81.7	1,404.713	-1,136.613	01111012	25
	39.9	1,402.283	-1,136.999	02011524	
	68.9	1,404.638	-1,141.364	03120109	

Note: YYMMDDHH = Year, Month, Day, Hour Ending
LCC = Lambert Conic Conformal
NA = Not Applicable

[a] Based on the CALPUFF model using 3 years of CALMET meteorological data for 2001, 2002, and 2003, 4-km Florida domain.

[b] A "0.00" impact means that the predicted concentration was zero or less. The CALPUFF model does not print a negative concentration.

TABLE I-8
GP PALATKA MILL'S CONTRIBUTION TO TIME PERIODS PREDICTED TO EXCEED THE 24- AND 3-HOUR ALLOWABLE SO_2 INCREMENT AT THE CHASSAHOWITZKA NWA PSD CLASS I AREA

Year	Julian Day	Month	Day	Hour Ending for Period	Maximum Concentration ($\mu g/m^3$)[a]		Class I Significant Impact Level ($\mu g/m^3$)	Affected Chassahowitzka NWA Receptors[c]
					All Modeled Sources	GP Palatka PSD Only[b]		
3-Hour Exceedances								
2001	314	11	10	12	81.7	<.001	1.0	35-36, 39-113
2001	314	11	10	15	78.9	<.001	1.0	51, 52, 59, 89, 95, 101, 106, 107, 112, 113
2002	15	1	15	24	39.9	<.0001	1.0	45, 60, 62, 69, 71, 90, 96, 102, 108
2002	15	1	15	21	31.2	<.0001	1.0	54, 84
2002	42	2	11	21	30.9	<.0001	1.0	87, 93, 94, 98, 99, 100
2002	44	2	13	9	31.4	<.0001	1.0	60, 61, 69, 70, 76, 77, 83, 96, 102, 108
2002	332	11	28	9	29.2	<.00001	1.0	108
2002	361	12	27	9	30.1	0.52	1.0	60, 90, 109
2002	361	12	27	12	33.7	0.026	1.0	45, 53, 54, 61, 67-70, 77, 83, 90-91, 96,102, 104-105, 109-111
2003	335	12	1	6	62.0	< 0.06	1.0	37, 45-48, 53-56, 90-94, 98, 99
2003	335	12	1	9	68.9	< 0.05	1.0	57, 60-65, 69-74, 77-81, 83-87
24-Hour Exceedances								
2002	30	1	30	24	5.24	< .00001	0.2	15, 19, 20, 21
2002	352	12	18	24	5.39	0.022	0.2	1-18
2002	361	12	27	24	5.85	0.12	0.2	90
2003	238	8	26	24	5.72	< .001	0.2	4, 9, 15, 21, 40-44, 48-52, 57-59, 65
2003	239	8	27	24	7.75	< .0001	0.2	1-37
2003	279	10	6	24	7.08	0.073	0.2	9, 15, 36, 38-47, 50, 53-56, 61-64, 70-71
2003	335	12	1	24	6.54	0.026	0.2	47, 65, 75, 82, 88, 97, 100, 105

[a] Based on the CALPUFF model using 3 years of CALMET meteorological data for 2001, 2002, and 2003, 4-km Florida domain.

[b] Includes only GP Palatka PSD sources.

[c] Based on 113 National Park Service receptors for Chassahowitzka NWA.

TABLE I-9
MAXIMUM PREDICTED SO_2 IMPACTS FOR COMPARISON TO THE FLORIDA AAQS INCLUDES START-UP EMISSIONS FOR GP RECOVER BOILER NO 4

	Concentrations (µg/m³)[a]			Receptor Location UTM Coordinates (m)			
Averaging Time and Rank	**Total (c=a+b)**	**Modeled Sources (a)**	**Background[b] (b)**	**East**	**North**	**Time Period (YYMMDDHH)**	**Florida Ambient Air Quality Standards (µg/m³)**
Highest Annual							
	32.0	26.0	6	434741	3283275	01123124	60
	29.7	23.7	6	434704	3283247	02123124	
	32.5	26.5	6	434629	3283191	03123124	
	30.6	24.6	6	434741	3283275	04123124	
	31.9	25.9	6	434704	3283247	05123124	
HSH 24-Hour							
	202	168	34	434704	3283247	01030524	260
	221	187	34	434554	3283135	02010724	
	218	184	34	434666	3283219	03121724	
	192	158	34	434704	3283247	04040224	
	207	173	34	434592	3283163	05040224	
HSH 3-Hour							
	775	647	128	434629	3283191	01122612	1,300
	792	664	128	434554	3283135	02101612	
	707	579	128	434629	3283191	03042618	
	783	655	128	434629	3283191	04041415	
	784	656	128	434629	3283191	05042718	

Note: YYMMDDHH = Year, Month, Day, Hour Ending.
HSH = Highest, second-highest
AAQS = Ambient Air Quality Standards

[a] Concentrations are based on highest concentrations predicted using AERMOD with five years of meteorological data from 2001 to 2005 of surface and upper air data from the National Weather Service station at Jacksonville International Airport as received from the FDEP.

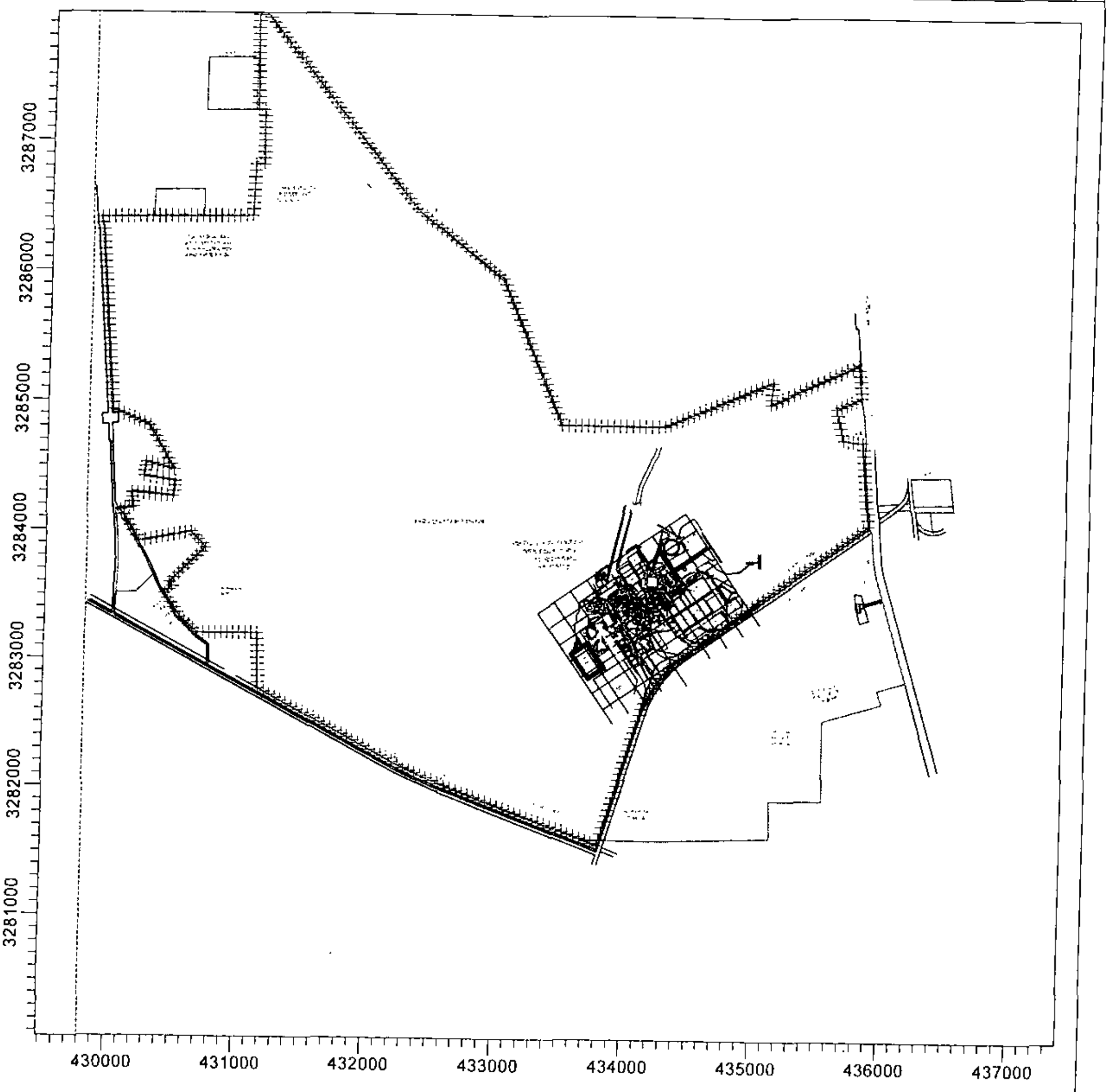
[b] Background concentrations are highest mean and HSH 24-and 3-hour concentrations, measured during 2004 and 2005 from Palatka monitoring station 12-107-1008.

ATTACHMENT J (Q-36)

Facility Plot Plan – Showing boundaries and UTM
AutoCAD format sent electronically

PROJECT TITLE:

GP PALATKA NEW PROPERTY BOUNDARY



COMMENTS

SOURCES: 34

COMPANY NAME:

RECEPTORS: 2124

MODELER:

SCALE: 1:48,286

0 1 km

DATE: 9/22/2006

PROJECT NO.:

ISC-AERMOD View - Lakes Environmental Software

V:\Projects\GP\PALATKA\Cumulative Project Calpuff\BPIP\GPGRID1.isc

ATTACHMENT K (Q-2)

Table 3-1 (11/14/01); GP-EU1-G8 a & b (10/29/03)

Table 3-1. TRS, SO_2, and SAM Emissions Due to NCG/SOG Destruction:

Final Compliance Scenario: LVHC NCGs and SOGs to New Thermal Oxidizer with No. 4 Combination Boiler Backup

NCG Source	Uncontrolled TRS Emissions (a) (lb/hr)	Potential Uncontrolled SO_2 Emissions (lb/hr)	Sulfur Removal Efficiency (%)	SO_2 Control Efficiency (%)	Maximum SO_2 Emission Rate		Controlled TRS Emission Rate		Maximum SAM Emission Rate	
					lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
OPTION 1: LVHC/SOGs to NEW THERMAL OXIDIZER @ 100%										
LVHC NCGs	378	756	60 (b)	95 (c)	15.1	66.2				
Condensate Stripper Off-Gas	162	324	0	95 (c)	16.2	71.0				
TOTALS	540				**31.3**	**137.2**	**0.16 (f)**	**0.71**	**2.2 (h)**	**9.6**
OPTION 2: LVHC/SOGs to NEW THERMAL OXIDIZER @ 80%; NO. 4 CB @ 20%										
TO NEW THERMAL OXIDIZER @ 80%:										
LVHC NCGs	378	756	60 (b)	95 (c)	15.1	53.0				
Condensate Stripper Off-Gas	162	324	0	95 (c)	16.2	56.8				
Subtotal	540				**31.3**	**109.7**	**0.16 (f)**	**0.57**	**2.2 (h)**	**7.7**
TO NO. 4 COMBINATION BOILER @ 20%:										
LVHC NCGs	378	756	60 (b)	0 (d)	302.4	264.9	0.378 (g)	0.33	12.1 (i)	10.6
Condensate Stripper Off-Gas	162	324	0	0 (d)	324.0	283.8	0.162 (g)	0.14	13.0 (i)	11.4
Subtotal	540				**626.4**	**548.7**	**0.54**	**0.47**	**25.1**	**21.9**
TOTALS						**658.5 (d)** **389.2 (e)**		**1.04**		**29.7**

Note:

NCG = noncondensable gases
TRS = total reduced sulfur
SO_2 = sulfur dioxide
SAM = sulfuric acid mist
LVHC = low volume, high concentration

(a) As sulfur, for pulp production rate of 1,850 TPD ADUP. Based on engineering estimates and test data, which shows 70%/30% split of S between NCGs/SOGs.

(b) TRS pre-scrubber provides minimum of 60% sulfur removal.

(c) Design efficiency of SO_2 scrubber serving the new Thermal Oxidizer.

(d) No removal of SO_2 in No. 4 Combination Boiler is assumed.

(e) NCASI studies show that there is SO_2 absorption in the boiler from bark burning. Based on this study, the average SO_2 removal when burning carbonaceous fuels is as follows.

Sulfur capture derivation:

avg tons bark =	35 TPH
sulfur input due to TRS burning =	313
tons wood per lb sulfur input = X =	0.1117
% capture = $122.34 \cdot X^{0.5}$ =	40.9 %

Reference: NCASI Tech. Bulletin 640, Sept. 1992.

(f) Based on Florida limit of 5 ppmvd @ 10% O_2 and new Thermal Oxidizer flow rate of 6,160 dscfm @ 10% O_2.

(g) Assumes 99.9% TRS destruction in new Thermal Oxidizer or combination boiler.

(h) Vendor information for emissions after candle mist eliminator.

(i) Assumes SAM emissions are equivalent to 4% of SO_2 emissions, based on AP-42 for combustion sources.

Attachment GP-EU1-G8a. Estimated Maximum Short-Term TRS, SO_2, and SAM Emissions From Power Boilers Due to HVLC DNCG Stream Combustion Only, Georgia-Pacific Palatka

Source	Uncontrolled TRS Emissions [a] (lb S/ton ADUP)	Maximum Pulp Production Rate [b]		Maximum SO_2 Emission Rate [d]		Maximum TRS Emission Rate (lb/hr)	Maximum SAM Emission Rate [g]	
		tons/hr ADUP	tons/day ADUP	lb/hr	lb/day		lb/hr	lb/day
SCENARIO 1: NO. 4 COMBINATION BOILER								
HVLC DNCGs	0.35	118.0	2,300	82.6	1,610	3.6 [e]	3.3	64.4
SCENARIO 2: NO. 5 POWER BOILER								
HVLC DNCGs	0.35	118.0	2,300	82.6	1,610	3.9 [f]	3.3	64.4

Notes:

NCG = noncondensable gases

DNCG= dilute NCG

S= sulfur

SO_2 = sulfur dioxide

HVLC = high volume, low concentration

TRS = total reduced sulfur

ADUP= air-dried unbleached pulp

Footnotes:

(a) As sulfur. Based on worst-case engineering estimate from AMEC Forest Industry Consulting.

(b) Maximum hourly rate based on existing permit limit; maximum daily rate based on proposed limitation.

(c) SO_2 calculated as potential sulfur emissions times two, based on MW sulfur = 32 and MW of SO2 = 64.

(d) No removal of SO_2 in either boiler is assumed.

(e) Based on 5 ppmvd @ 10% O_2 and actual flow rate from stack test data (135,400 dscfm @ 10% O_2).

(f) Based on 5 ppmvd @ 10% O_2 and actual flow rate from stack test data (147,200 dscfm @ 10% O_2).

(g) Assumes SAM emissions are equivalent to 4% of SO_2 emissions, based on AP-42 for combustion sources.

Attachment GP-EU1-G8b. Estimated Maximum Annual TRS, SO_2 and SAM Emissions From Power Boilers Due to HVLC DNCG Stream Combustion Only,
Georgia-Pacific Palatka

Source	Uncontrolled TRS Emissions [a] (lb S/ton ADUP)	Pulp Production Rate [b] (tons/yr ADUP)	Maximum SO_2 Emission Rate [d] (TPY)	Maximum TRS Emission Rate (TPY)	Maximum SAM Emission Rate [g] (TPY)
SCENARIO 1: NO. 4 COMBINATION BOILER 100% UPTIME					
HVLC DNCGs--No. 4 Combination Boiler @ 100%	**0.35**	675,250	236.3	15.69 [e]	9.45
SCENARIO 2: NO. 5 POWER BOILER 100% UPTIME					
HVLC DNCGs--No. 5 Power Boiler @ 100%	**0.35**	675,250	236.3	17.06 [f]	9.45

Notes:

NCG = noncondensable gases
DNCG= dilute NCG
S= sulfur
SO_2 = sulfur dioxide
HVLC = high volume, low concentration
ADUP= air-dried unbleached pulp
TRS = total reduced sulfur

Footnotes:

(a) As sulfur. Based on worst-case engineering estimate from AMEC Forest Industry Consulting.
(b) Based on 1,850 tons/day ADUP @ 365 days/yr.
(c) SO_2 calculated as potential sulfur emissions times two, based on MW sulfur = 32 and MW of SO2 = 64.
(d) No removal of SO_2 in either boiler is assumed.
(e) Based on 5 ppmvd @ 10% O_2 and actual flow rate from stack test data (135,400 dscfm @ 10% O_2).
(f) Based on 5 ppmvd @ 10% O_2 and actual flow rate from stack test data (147,200 dscfm @ 10% O_2).
(g) Assumes SAM emissions are equivalent to 4% of SO_2 emissions, based on AP-42 for combustion sources.

ATTACHMENT L (Q-9)

Updated Tables 2-1, 2-3, and 3-3 – No. 4 CB PSD

TABLE 2-1
SUMMARY OF PAST ACTUAL ANNUAL EMISSIONS FROM NO. 4 COMBINATION BOILER AND NO. 4 POWER BOILER, GP PALATKA

Source Description	EU ID	Pollutant Emission Rate (TPY)										
		SO_2	NO_x	CO	PM	PM_{10}	VOC	TRS	SAM	Lead	Mercury	Fluorides
No. 4 Power Boiler												
2001 Actual Emissions	014	296 2	36.2	3.85	19.8	17.2 [l]	0 22	--	13 0 [a, m]	0 0092	0 000087 [a, g]	0.029 [a, g]
2002 Actual Emissions		245 0	31.1	3.31	16 5	14.3	0 19	--	10.8 [a, m]	0.0010	0 000075 [a, g]	0 025 [a, g]
Average Actual Emissions		**270.6**	**33.6**	**3.58**	**18.1**	**15.7**	**0.20**	**--**	**11.9**	**0.005**	**0.000081**	**0.027**
No. 4 Combination Boiler	016	--	--	--	--	--	--	--	--	--	--	--
2004 Actual Emissions												
--Fuel Oil Usage		763 6 [j]	102 3	10.9	12 4 [c]	7.81 [e]	0.61	--	33.6 [a, m]	0 0033 [o]	0.00025 [h]	0 081 [a, h]
--Wood/Bark Usage		33.8	324.2 [b]	810 6	121.6 [d]	90 0 [f]	23.0 [k]	--	1.49 [a, m]	0.065 [p]	0.0047 [i]	--
--NCG/SOG Burning		281.9	19.1	--	--	--	--	0 47 [n]	12.4 [a, m]	--	--	--
--Total (Without NCGs/SOG)		**797.4**	**426.5**	**821.5**	**134.0**	**97.8**	**23.6**	**0.0**	**35.1**	**0.07**	**0.005**	**0.08**
2005 Actual Emissions												
--Fuel Oil Usage		828.3 [j]	108.9	11 6	13 3 [c]	8 37 [e]	0.65	--	36.4 [m]	0 0035 [o]	0.00026 [h]	0.086 [a, h]
--Wood/Bark Usage		30 3	291 0 [b]	727.4	50.9 [d]	37.7 [f]	20 6 [k]	--	1 33 [m]	0 058 [p]	0 0042 [i]	--
--NCG/SOG Burning		279.5	16.5	--	--	--	--	0 47 [n]	12.3 [m]	--	--	--
--Total (Without NCGs/SOG)		**858.6**	**399.9**	**739.0**	**64.2**	**46.1**	**21.3**	**0.0**	**37.8**	**0.06**	**0.005**	**0.09**
Average Actual Emissions												
--Total (Without NCGs/SOG)		**828.0**	**413.2**	**780.3**	**99.1**	**71.9**	**22.4**	**0.0**	**36.4**	**0.065**	**0.0047**	**0.084**

TPY = tons per year.

Footnotes:

[a] Not reported in AOR.

[b] NO_x from wood/bark based on 0.24 lb/MMBtu (converted to lb/ton wood/bark by multiplying by 9 MMBtu/ton) and actual wood/bark burning rate (300,219 TPY for 2004 and 269,420 TPY for 2005).

[c] PM based on the actual fuel oil usage (4,351,660 gal/yr in 2004 and 4,633,380 gal/yr in 2005), heat content of fuel oil (150,000 Btu/gal), and average of 2003-2005 stack test data (0 038 lb/MMBtu)

[d] PM based on the actual wood/bark burned (300,219 TPY in 2004 and 269,420 TPY in 2005), heat content of wood/bark (4,500 Btu/lb), and actual stack test data (0 09 lb/MMBtu on 1/8/04 and 0.042 lb/MMBtu on 8/18/05).

[e] PM_{10} = 63% of PM, which is based on AP-42 Section 1.3, Table 1.3-4, for utility boilers firing residual oil with an ESP. (Note: no factor available for industrial boiler with an ESP).

[f] PM_{10} = 74% of PM, which is based on the ratio of individual emission factors for PM and PM_{10} from AP-42 Table 1.6-1 for wood-residue fired boilers with an ESP (0 054 lb/MMBtu for PM, 0 04 lb/MMBtu for PM10) .

[g] Mercury and Fluoride emissions based on actual fuel oil usage (1,323,000 gal/yr for 2002 and 1,540,000 gal/yr for 2001) and emission factors from AP-42 Table 1.3-11 (Hg = 1.13E-04 lb/1000 gal; F = 3.73E-02 lb/1000 gal)

[h] Mercury and Fluoride emissions based on actual fuel oil usage (4,351,660 gal/yr in 2004 and 4,633,380 gal/yr in 2005) and emission factors from AP-42 Table 1.3-11 (Hg = 1.13E-04 lb/1000 gal; F = 3.73E-02 lb/1000 gal).

[i] Mercury based on actual wood/bark burned (300,219 TPY in 2004 and 269,420 TPY in 2005) and emission factor from AP-42 Table 1.6-4 (Hg = 3.5E-06 lb/MMBtu converted to 3.15E-05 lb/ton bark by multiplying by 9 MMBtu/ton).

[j] SO_2 emissions recalculated based on equation in Title V permit: 0.164 x %S x gallons fuel fired / 2000 lbs/ton = tons SO_2

[k] VOC revised based on updated AP-42 factor for wood firing of 0 017 lb/MMBtu, Lead based on 4 8E-05 lb/MMBtu

[l] Based on AP-42 Section 1.3, Table 1.3-5, for industrial boilers firing residual oil with no PM control device: 7.17*[1.12(%S)+0 37] lb/1000gal.

[m] Based on similar derivation of sulfuric acid mist from AP-42 for fuel oil (Table 1.3-1). 3.6% of SO_2 becomes SO_3 then take into account the ratio of sulfuric acid mist and sulfur trioxide molecular weights (98/80).

[n] Based on maximum permitted rate for TRS.

[o] Lead emissions based on actual fuel oil usage (4,351,660 gal/yr in 2004 and 4,633,380 gal/yr in 2005) and emission factors from AP-42 Table 1.3-11 (Pb = 1.51E-03 lb/1000 gal).

[p] Lead emissions based on actual wood/bark burned (300,219 TPY in 2004 and 269,420 TPY in 2005) and emission factors from AP-42 Table 1 6-4 (Pb = 4.8E-05 lb/MMBtu converted to 4.3E-04 lb/ton wood/bark by multiplying by 9 MMBtu/ton

Source: Annual Operating Reports submitted to Florida DEP, unless otherwise noted.

TABLE 2-3
PAST ACTUAL ANNUAL (2004-2005) EMISSIONS FOR THE NO. 4 COMBINATION BOILER AND OTHER PROJECTS, GP PALATKA

Source Description	EU ID	Pollutant Emission Rate (TPY)										
		SO_2	NO_x	CO	PM	PM_{10}	VOC	TRS	SAM	Lead	Mercury	Fluoride
2004 Actual Emissions [c]												
No. 4 Combination Boiler [b]	016	797.4	426.5	821.5	134.0	97.8	23.6	--	35.1	0.068	5.0E-03	0.081
No. 4 Lime Kiln	017	0.04	129.5	5.4	30.4	29.9	2.3	2.3	0.0017	0.160	--	--
No. 4 Recovery Boiler	018	17.4	464.7	1,285.0	213.0	159.8	1.2	8.9	2.4	0.012	6.7E-05	--
No. 4 Smelt Dissolving Tank	019	27.2	56.2	9.3	41.2	37.1	93.1	6.1	--	0.010	6.7E-05	--
Black Liquor/Green Liquor Tanks	042	--	--	--	--	--	9.6	3.0	--	--	--	--
Caustic Area	042	--	--	--	1.7	1.7	12.6	4.0	--	--	--	--
Bark Handling System (March 2005) [a]	--	--	--	--	14.6	10.6	175.4	--	--	--	--	--
2005 Actual Emissions [c]												
No. 4 Combination Boiler [b]	016	858.6	399.9	739.0	64.2	46.1	21.3	--	37.8	0.062	4.5E-03	0.086
No. 4 Lime Kiln	017	0.04	73.3	8.2	72.1	70.9	2.6	2.8	0.0018	0.160	--	--
No. 4 Recovery Boiler	018	12.0	481.7	1,213.5	56.3	42.2	17.8	13.7	0.53	0.012	6.9E-05	--
No. 4 Smelt Dissolving Tank	019	28.2	58.0	9.5	28.6	25.7	95.7	4.1	--	0.010	6.9E-05	--
Black Liquor/Green Liquor Tanks	042	--	--	--	--	--	9.7	3.0	--	--	--	--
Caustic Area	042	--	--	--	1.7	1.7	12.6	4.0	--	--	--	--
Bark Handling System (March 2005) [a]	--	--	--	--	14.6	10.6	175.4	--	--	--	--	--
Average 2004 & 2005 Actual Emissions												
No. 4 Combination Boiler	016	828.0	413.2	780.3	99.1	71.9	22.4	--	36.4	0.065	4.7E-03	0.084
No. 4 Lime Kiln	017	0.04	101.4	6.8	51.3	50.4	2.5	2.6	0.0018	0.160	--	--
No. 4 Recovery Boiler	018	14.7	473.2	1,249.3	134.7	101.0	9.5	11.3	1.47	0.012	6.8E-05	--
No. 4 Smelt Dissolving Tank	019	27.7	57.1	9.4	34.9	31.4	94.4	5.1	--	0.010	6.8E-05	--
Black Liquor/Green Liquor Tanks	042	--	--	--	--	--	9.7	3.0	--	--	--	--
Caustic Area	042	--	--	--	1.7	1.7	12.6	4.0	--	--	--	--
Bark Handling System (March 2005)	--	--	--	--	14.6	10.6	175.4	--	--	--	--	--

[a] Based on PSD Application for Replacement of the Bark Hog, dated July 2004. Emissions did not increase in 2005.

[b] See Table 2-1.

[c] See Appendix C for emission calculations, unless otherwise noted.

TABLE 3-3
CONTEMPORANEOUS AND DEBOTTLENECKING EMISSIONS ANALYSIS AND PSD APPLICABILITY
NO. 4 COMBINATION BOILER, GP PALATKA

Source Description	Pollutant Emission Rate (TPY)										
	SO$_2$	NO$_x$	CO	PM	PM$_{10}$	VOC	TRS	SAM	Lead	Mercury	Fluoride
Future Potential Emissions[a]											
No. 4 Combination Boiler - 2.35% S	1,023.7	496.5	1,010.5	80.8	59.8	34.4	--	45.0	0.097	0.0071	0.095
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	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[b]	33.7	69.6	11.4	55.2	49.7	115.0	14.9	--	0.013	8.3E-05	--
Black Liquor/Green Liquor Tanks[b]	--	--	--	--	--	14.0	3.7	--	--	--	--
Caustic Area[b]	--	--	--	2.6	2.6	18.9	5.8	--	--	--	--
Other Projects											
Bark Handling System[c]	--	--	--	22.8	13.9	475.8	--	--	--	--	--
Total- Future Potential	**1,251.3**	**1,601.6**	**3,339.0**	**622.7**	**502.3**	**791.5**	**83.8**	**62.7**	**0.37**	**0.0072**	**0.095**
Past Actual Emissions[d]											
No. 4 Combination Boiler	828.0	413.2	780.3	99.1	71.9	22.4	--	36.4	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	--	--
No. 4 Recovery Boiler	14.7	473.2	1,249.3	134.7	101.0	9.5	11.3	1.5	0.012	6.8E-05	--
No. 4 Smelt Dissolving Tank[b]	27.7	57.1	9.4	34.9	31.4	94.4	5.1	--	0.010	6.8E-05	--
Black Liquor/Green Liquor Tanks[b]	--	--	--	--	--	9.7	3.0	--	--	--	--
Caustic Area[b]	--	--	--	1.7	1.7	12.6	4.0	--	--	--	--
Other Projects											
Bark Handling System[c]	--	--	--	14.6	10.6	175.4	--	--	--	--	--
Total- Past Actual	**870.4**	**1,044.9**	**2,045.7**	**336.2**	**267.0**	**326.4**	**25.9**	**37.9**	**0.25**	**0.0049**	**0.084**
Increase Due to Project	**380.9**	**556.7**	**1,293.3**	**286.5**	**235.3**	**465.1**	**57.8**	**24.8**	**0.13**	**0.0024**	**0.011**
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	--	--	--
--Increase Due to Modified No. 4 Comb. Boiler	548.7	37.8	--	--	--	--	0.47	21.9	--	--	--
--Increase Due to BSW System w/Condensate Treatment	--	--	--	--	--	48.6	58.7	--	--	--	--
--Decrease Due to Existing Thermal Oxidizer	-749.8	-49.5	-0.3	-20.6	-20.6	-3.2	-0.3	-26.9	--	--	--
--Decrease Due to Existing BSW System w/o Condensate Treatment	--	--	--	--	--	-52.1	-62.9	--	--	--	--
--Net Change	-91.4	139.7[e]	8.5	10.1	10.1	2.4	-3.14	2.7	--	--	--
New Package Boiler (9/02) (Permit No. 1070005-018-AC) - startup Oct. 2002											
--Increase Due to New Package Boiler (EU 044)	0.1	39.4	16.5	1.5	1.5	1.1	--	--	f	f	f
--Decrease from old No. 6 Package Boiler	-0.07	-9.2	-2.1	-0.15	-0.15	--	--	--	f	f	f
--Net Change	0.03	30.20	14.40	1.35	1.35	1.1	--	--	f	f	f
Brown Stock Washer and Oxygen Delignification System (7/04) (Permit No. 1070005-024-AC) - startup Feb. 2006											
--Increase Due to No. 4 Comb. Boiler/No. 5 Power Boiler	236.3	--	0.3	--	--	4.0	17.1	9.5	--	--	--
--Increase Due to Pulp Storage Tanks	--	--	--	--	--	63.1	9.6	--	--	--	--
--Decrease from existing BSW System, BL Filter, etc	--	--	--	--	--	-128.5	-77.1	--	--	--	--
--Net Change	236.3[e]	--	0.3	--	--	-61.4	-50.4	9.5	--	--	--
No. 4 Power Boiler Shutdown (Sep. 2003)	-270.6	-33.6	-3.6	-18.1	-15.7	-0.2	--	-11.9	-0.005	-0.000081	-0.027
Total Contemporaneous Emission Changes	**-362.0**	**-3.4**	**19.6**	**-6.7**	**-4.3**	**-58.10**	**-53.5**	**0.3**	**-0.005**	**-0.000081**	**-0.027**
TOTAL NET CHANGE	**18.9**	**553.3**	**1,312.9**	**279.8**	**231.0**	**407.0**	**4.3**	**25.1**	**0.12**	**0.0023**	**-0.015**
PSD SIGNIFICANT EMISSION RATE	40	40	100	25	15	40	10	7	0.6	0.1	3.0
PSD REVIEW TRIGGERED?	No	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	No	**Yes**	No	No	No

Notes:

[a] No. 4 Combination Boiler potential emissions from Table 2-2, and Tables B-1 and B-2 (without NCGs, SOG, DNCGs). All other sources based on calculations in Appendix D.

[b] Sources will potentially be "affected" as part of the No. 4 Recovery Boiler tube replacement project.

[c] As estimated by FDEP in Technical Evaluation and Preliminary Determination for Bark Hog Replacement PSD, November 2004.

[d] For No. 4 Combination Boiler, based on actual emissions for 2004 and 2005 from Table 2-1 (without NCGs, SOG, DNCGs). For all other sources, based on Table 2-3 and Appendix C.

[e] Pollution Control Projects (PCP) approved for G-P Palatka Mill, excluded from PSD review.

[f] Since project increase does not exceed PSD significant emission rate, netting is not performed for this pollutant.