

# **Prevention of Significant Air Quality Deterioration Review**

## **Preliminary Determination**

Facility Name: Graphic Packaging International, Inc.  
City: Macon  
County: Bibb  
AIRS Number: 04-13-02100001  
Application Number: 20207

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Review Conducted by:  
State of Georgia - Department of Natural Resources  
Environmental Protection Division - Air Protection Branch  
Stationary Source Permitting Program

Prepared by:

Wendy Troemel – Chemicals Unit  
Susan Jenkins – Chemicals Unit

Modeling Approved by:

Yan Huang - Data and Modeling Unit  
Peter Courtney – Data and Modeling Unit

Reviewed and Approved by:

David Matos – Chemicals Unit Coordinator  
Eric Cornwell – Stationary Source Permitting Program Manager  
James Capp – Chief, Air Protection Branch

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## **SUMMARY**

The Environmental Protection Division (EPD) has reviewed the application submitted by Graphic Packaging International, Inc. (GPI) for a permit to expand utilization of biomass energy, allow the mill to be largely self-sufficient from an electrical power generation standpoint, and substantially reduce reliance on coal combustion.

The proposed project will install a new bubbling fluidized bed (BFB) boiler (No. 3 Biomass Boiler), rated at approximately 620 MMBtu/hr to be equipped with flue gas recirculation, a baghouse, a selective non-catalytic (SNCR) reduction system, and potentially an acid gas control system (some type of sorbent injection). The No. 3 Biomass Boiler will combust biomass, natural gas, and mill wastewater treatment plant (WWTP) sludge. The facility will shutdown existing No. 1 Power Boiler which combusts coal, fuel oil, and natural gas upon normal operation of No. 3 Biomass Boiler. Coal and fuel oil will no longer be used as fuel in the No. 2 Power Boiler with natural gas combustion capability being retained. Existing biomass fuel storage and handling system will be supplemented with new conveyors to transport biomass to the No. 3 Biomass Boiler. A new sand silo with fabric filtration system and associated conveyors will be installed to accommodate the BFB sand bed. A new fly ash handling system and ash storage silo with fabric filtration system will be constructed to accommodate the fly ash captured by the new baghouse associated with the No. 3 Biomass Boiler. New bottom ash and boiler hopper ash handling equipment will be installed to remove and store the bottom ash generated by the No. 3 Biomass Boiler. A sorbent handling system and storage silo equipped with a fabric filtration system may be required. The facility will also install a new steam turbine generator rated at 40 MW and new cooling tower and generator lube oil and hydraulic oil process tanks to support the new steam turbine.

The modification of the facility due to this project will result in an emissions increase in carbon monoxide (CO), nitrogen oxides (NO<sub>x</sub>), sulfur dioxide (SO<sub>2</sub>), filterable particulate matter (PM), particulate matter less than 10 micrometers (PM<sub>10</sub>), fine particulate matter (PM<sub>2.5</sub>), volatile organic compounds (VOC), greenhouses gases (as CO<sub>2</sub>e), and sulfuric acid (H<sub>2</sub>SO<sub>4</sub>). A Prevention of Significant Deterioration (PSD) analysis was performed for the facility for all pollutants to determine if any net increase was above the “significance” level. The CO emissions increase was above the PSD significant level threshold.

The GPI Mill is located in Bibb County, which is classified as “attainment” or “unclassifiable” for SO<sub>2</sub>, PM<sub>10</sub>, NO<sub>x</sub>, CO, and ozone (VOC). Bibb County is classified as nonattainment for PM<sub>2.5</sub>.

The EPD review of the data submitted by GPI related to the proposed modifications indicates that the project will be in compliance with all applicable state and federal air quality regulations.

It is the preliminary determination of the EPD that the proposal provides for the application of Best Available Control Technology (BACT) for the control of CO as required by federal PSD regulation 40 CFR 52.21(j).

It has been determined through approved modeling techniques that the estimated emissions will not cause or contribute to a violation of any ambient air standard or allowable PSD increment in the area surrounding the facility. It has further been determined that the proposal will not cause impairment of visibility or detrimental effects on soils or vegetation. Any air quality impacts produced by project-related growth should be inconsequential.

This Preliminary Determination concludes that an Air Quality Permit should be issued to GPI for the modifications necessary to expand utilization of biomass energy, allow the mill to be largely self-sufficient from an electrical power generation standpoint, and substantially reduce reliance on coal combustion. Various conditions have been incorporated into the current Title V operating permit to ensure and confirm compliance with all applicable air quality regulations. A copy of the draft permit amendment is included in Appendix A. This Preliminary Determination also acts as a narrative for the Title V Permit.

## **1.0 INTRODUCTION – FACILITY INFORMATION AND EMISSIONS DATA**

On January 28, 2011 (application did not include modeling), February 28, 2011 (modeling portion of application), April 19, 2011 (modeling update) April 19, 2011 (update to include Boiler MACT requirements and revised calculations), and August 10, 2011 (final update to exclude Boiler MACT and carbon dioxide biogenic emissions from biomass combustion, as well as a consolidation of all previous updates for both emissions Calculations and Modeling), Graphic Packaging International, Inc. (hereafter GPI) submitted an application for an air quality permit to expand utilization of biomass energy, allow the mill to be largely self-sufficient from an electrical power generation standpoint, and substantially reduce reliance on coal combustion. The facility is located at 100 Graphic Packaging International Way in Macon, Bibb County.

### **Existing PSD Classification**

GPI is classified as a major source under PSD permitting program because it emits more than 100 tpy of a regulated pollutant. Pulp and paper mills are on the list of 28 industry categories subject to the 100 tpy major source thresholds. The facility has undergone a PSD review at least three times (1978, 1990, and 1996) and a PCP review once (2001). The following limits are the result of the PSD and PCP reviews.

- The Nos. 1 and 2 Lime Kilns are limited to 3.5 lb/ton of CaO produced for NO<sub>x</sub> (BACT - 1996).
- The Nos. 1 and 2 Lime Kilns are limited to 0.064 gr/dscf PM corrected to 10% oxygen when gaseous fossil fuel is burned, or 0.13 gr/dscf corrected to 10% oxygen when liquid fossil fuel is burned (1996). The original PSD limit was 0.067 gr/dscf; however, it was determined that 40 CFR 60 Subpart BB incorrectly converted 0.15g/dscm to 0.067 gr/dscf. The correct conversion is 0.064 gr/dscf, as seen in 40 CFR 63 Subpart MM. Therefore, these limits did not actually change; they were simply corrected.
- The No. 3 Recovery Boiler is limited to 54.4 lb/hour (or 0.027 gr/dscf of PM corrected to 8% oxygen) of PM (BACT - 1990). This limit was originally set at 39.2 lb/hr, but was corrected in May 1992 when it was determined that the value was calculated at 3% oxygen instead of 8% oxygen.
- The No. 3 Recovery Boiler is limited to 196 lb/hour SO<sub>2</sub> (PCP - 2001).
- The No. 3 Recovery Boiler is limited to 202.1 lb/hour (or 120 ppm on a dry basis corrected to 8% oxygen) NO<sub>x</sub> (BACT - 1990).
- The No. 3 Recovery Boiler is limited to 205.1 lb/hour CO (BACT - 1990). This limit was originally set at 146.5 lb/hr, but was corrected in May 1992 when it was determined that the value was calculated at an incorrect molecular weight (20 instead of 28).
- The No. 3 Recovery Boiler is limited to 11.0 lb/hour (or 5 ppm on a dry basis corrected to 8% oxygen) of TRS compounds (PSD).
- The Smelt Tank is limited to 10.5 lb/hour (or 0.12 lb/ton of black liquor solids) of PM (BACT - 1996).
- The Smelt Tank is limited to 1.5 lb/hour (or 0.0168 lb/ton of black liquor solids) of TRS (PSD).
- The No. 2 Biomass Boiler is limited to 0.1 lb/MMBTU heat input PM (BACT –1978).
- The No. 2 Biomass Boiler is limited to 20% opacity through continuous monitoring of the pressure drop and scrubber flow rate through the scrubber (BACT –1978).

The following PSD limits have been subsumed by later limits.

- The No. 2 Biomass Boiler was initially limited to 1.2 lb SO<sub>2</sub>/MMBtu heat input for solid fossil fuels. However, as other fuels were permitted to be burned in the boiler, the limit has been changed to the prorated equation in 40 CFR 60.43(b), which effectively subsumes the PSD limit. (BACT –1978).
- The No. 2 Biomass Boiler was initially limited to 0.7 lb NO<sub>x</sub>/MMBtu heat input for solid fossil fuels. However, as other fuels were permitted to be burned in the boiler, the limit has been changed to the prorated equation in 40 CFR 60.44(b), which effectively subsumes the PSD limit. (BACT –1978).

The following limit has been taken to avoid PSD review.

- The Nos. 1 and 2 Lime Kilns are limited to 41.6 lb/hour of SO<sub>2</sub>.

### Part 70 Applicability

**Table 1-1: Title V Major Source Status**

Pollutant	Is the Pollutant Emitted?	If emitted, what is the facility's Title V status for the Pollutant?		
		Major Source Status	Major Source Requesting SM Status	Non-Major Source Status
PM	Yes	X		
PM <sub>10</sub>	Yes	X		
SO <sub>2</sub>	Yes	X		
VOC	Yes	X		
NO <sub>x</sub>	Yes	X		
CO	Yes	X		
TRS	Yes	X		
H <sub>2</sub> S	Yes	X		
Individual HAP	Yes	X		
Total HAPs	Yes	X		

Table 1-2 below lists all current Title V permits, all amendments, 502(b)(10) changes, and off-permit changes, issued to the facility, based on a review of the "Permit" file(s) on the facility found in the Air Branch office.

**Table 1-2: List of Current Permits, Amendments, and Off-Permit Changes**

Permit Number and/or Off-Permit Change	Date of Issuance/ Effectiveness	Purpose of Issuance
2631-021-0001-V-03-0	3/10/2008	Renewal Permit
2631-021-0001-V-03-1	1/25/2011	Section 502(b)(10) change for modifications to the No. 1 Paper Machine (Group Code P00A)

### PSD Applicability

A PSD pre-construction permit is required when construction of a new emissions unit, or a project at an existing emissions unit (i.e., a physical change or change in the method of operation), results in a significant emissions increase and a significant net emissions increase in the annual emission rate of a regulated NSR pollutant.

### PSD Applicability – Significant Emissions Increase

Chapter 3 and Tables B-1 and B-2 of Application No. 20207 provide the emission calculations from the applicant. These calculations have been reviewed and approved by the Division. Based on the proposed project description and data provided in the permit application, the estimated project potential to emit (PTE) of regulated NSR pollutants are listed in Table 1-3 [as taken from Table B-1 dated 8/10/2011]. The project emissions include emissions from new No. 3 Biomass Boiler, ancillary equipment, and new fuel-firing scenario with No. 2 Power Boiler.

**Table 1-3: PSD Project Potential to Emit**

Pollutant	Bibb County Classification	Precursor for which NAAQS	No. 3 Biomass Boiler PTE (tpy)	Ancillary Equipment & No. 2 Power Boiler PTE (tpy)	Total Potential Emissions Increase (tpy)	PSD Significant Emission Rate (tpy)	Subject to PSD Review
PM	NA	NA	127.6	-79.9	47.8	25	Yes
PM <sub>10</sub>	Attainment	NA	133.1	-64.3	68.7	15	Yes
PM <sub>2.5</sub>	Nonattainment	PM <sub>2.5</sub>	108.6	-53	55.6	10	Yes
VOC	(ozone) – Attainment	Ozone	27.2	3.4	30.5	40	No
NO <sub>x</sub>	NO <sub>2</sub> – Attainment	Ozone PM <sub>2.5</sub>	404.6	-118.5	286.1	40	Yes
CO	Attainment	NA	407.3	11.5	418.8	100	Yes
SO <sub>2</sub>	Attainment	PM <sub>2.5</sub>	869.0	-674.5	194.5	40	Yes
TRS	NA	NA	NA	NA	NA	10	No
Pb	Attainment	NA	0.1	NA	0.1	0.6	No
Fluorides	NA	NA	NA	NA	NA	3	No
H <sub>2</sub> S	NA	NA	NA	NA	NA	10	No
H <sub>2</sub> SO <sub>4</sub> (SAM)	NA	NA	13.2	-3.2	9.9	7	Yes
CO <sub>2</sub> e**	NA	NA	153,021.6	9040.2	162,061.9	0 *	Yes

\*CO<sub>2</sub>e has a PSD Significant Emission Rate of 0 tpy.

\*\* Based on a ruling signed by EPA on July 1, 2011 and published in the Federal Register on July 20, 2011 (Vol. 76, No. 139, page 43490), greenhouse gas (GHG) permitting requirements for carbon dioxide (CO<sub>2</sub>) emissions from biomass-fired and other biogenic sources are deferred for a period of three years. During the next three years, the EPA will conduct a “study to consider technical issues that must be resolved in order to account for biogenic CO<sub>2</sub> emissions in ways that are scientifically sound and also manageable in practice.” EPA will also develop “a final rule by the conclusion of the three year deferral period regarding how biogenic CO<sub>2</sub> emissions should be treated and accounted for in PSD and Title V permitting based on the feedback from the scientific and technical review.” The CO<sub>2</sub> emission values include CO<sub>2</sub> emissions from biogenic sources.

Bibb County is classified as nonattainment for PM<sub>2.5</sub> as of the date of this Preliminary Determination. Appendix S of Part 51 specifies the major source thresholds as 100 tpy of direct PM<sub>2.5</sub> and 100 tpy of SO<sub>2</sub> emissions. The regulated NSR pollutant NO<sub>x</sub> becomes regulated as a PM<sub>2.5</sub> precursor in June 2011 with a major source threshold of 100 tpy. Based on the proposed project description and data provided in the permit application, the estimated project PTE of regulated NSR pollutants subject to nonattainment NSR are listed in Table 1-4 below [as taken from Table B-1 dated 8/10/2011]

**Table 1-4: NNSR\* Project Potential to Emit**

Pollutant	Bibb County Classification	Precursor for which NAAQS	Potential Emissions Increase (tpy)	NNSR Major Source Threshold (tpy)	Subject to NNSR?
PM <sub>2.5</sub>	Nonattainment	PM <sub>2.5</sub>	55.6	10	Yes
NO <sub>x</sub>	NO <sub>2</sub> – Attainment	Ozone PM <sub>2.5</sub> **	286.1	40	Yes**
SO <sub>2</sub>	Attainment	PM <sub>2.5</sub>	194.5	40	Yes

\*NNSR = Nonattainment New Source Review.

\*\* Permit will be issued after June 2011 which is the date that NO<sub>x</sub> may be regulated as a PM<sub>2.5</sub> precursor for New Source Review purposes.

**PSD Applicability – Net Emissions Increase**

Chapter 3 and Tables B-1 and B-2 of Application No. 20207 provide the emission calculations from the applicant. These calculations have been reviewed and approved by the Division. As shown in Table 1-3, project PTE (alone) exceed the PSD major modification thresholds for CO, NO<sub>x</sub>, SO<sub>2</sub>, PM, PM<sub>10</sub>, PM<sub>2.5</sub>, CO<sub>2e</sub>, and SAM. As shown in Table 1-4, project PTE (alone) exceed the NNSR major modification threshold for PM<sub>2.5</sub>, NO<sub>x</sub>, and SO<sub>2</sub> emissions. GPI reviewed all projects completed at the Macon Mill within the past five years to determine the total emissions increase of CO, NO<sub>x</sub>, SO<sub>2</sub>, PM, PM<sub>10</sub>, PM<sub>2.5</sub>, CO<sub>2e</sub>, and SAM for comparison to the applicable NSR thresholds as part of the net emissions increase analysis. As the proposed project may begin construction in 2011, the five calendar year period to review includes 2007 through 2011.

Data specified in Table 1-5a was taken from Tables B-2 and B-6 of the application (dated 8/10/2011). Data specified in Table 1-5b was taken from Table B-2 of the application (dated 8/10/2011).

Note: The CO<sub>2e</sub> emission values specified in Table 1-5A, 1-5B, 1-5C, and 1-6 include CO<sub>2</sub> emissions from biogenic combustion.

**Table 1-5a: Net Change in Emissions Due to the Major PSD Modification – Shutdown of No. 1 Power Boiler**

Pollutant	Decrease from Shutdown of No. 1 Power Boiler		Associated Units Increase (tpy)	Total Decrease (tpy)
	Past Actual	Future Actual		
NO <sub>x</sub>	262.06	0	0	-262.06
CO	9.15	0	0	-9.15
SO <sub>2</sub>	668.81	0	0	-668.81
Total PM	75.5	0	0	-75.5
PM <sub>10</sub>	62.5	0	0	-62.5
PM <sub>2.5</sub>	53.9	0	0	-53.9
SAM	3.25	0	0	-3.25
CO <sub>2e</sub>	93,412.40	0	0	-93,412.40

**Table 1-5b: Net Change in Emissions Due to the Major PSD Modification – No. 1 Paper Machine Steam Upgrades**

Pollutant	Increase from 2010 Project		Associated Units Increase (tpy)	Total Increase (tpy)
	Past Actual	Future Actual		
NO <sub>x</sub>		14.2	0	14.2
CO		12.1	0	12.1
SO <sub>2</sub>		14.37	0	14.37
SAM		0.2	0	0.2
Total PM		7.45	0	7.45
PM <sub>10</sub>		4.4	0	4.4
PM <sub>2.5</sub>		4.1	0	4.1
CO <sub>2e</sub>	NA	NA	NA	NA

**Table 1-5c: Net Change in Emissions Due to the Major PSD Modification – North Biomass Feed System Restoration**

Pollutant	Increase from 2011 Project		Associated Units Increase (tpy)	Total Increase (tpy)
	Past Actual	Future Actual		
Total PM		6.4	0	6.4
PM <sub>10</sub>		3.8	0	3.8
PM <sub>2.5</sub>		3.8	0	3.8

Data specified in Table 1-6 was taken from Table B-2 of the application (8/10/2011) and is the sum of the project PTE shown in Table 1-3 and the net changes in emissions due to past projects shown in Tables 1-5.

**Table 1-6: Net Five-Year Contemporaneous Period Projects Emission Summary**

	<b>CO (tpy)</b>	<b>NO<sub>x</sub> (tpy)</b>	<b>SO<sub>2</sub> (tpy)</b>	<b>SAM (tpy)</b>	<b>Total PM (tpy)</b>	<b>PM<sub>10</sub> (tpy)</b>	<b>PM<sub>2.5</sub> (tpy)</b>	<b>CO<sub>2</sub>e (tpy)</b>
Total Contemporaneous Period Emissions (tpy)	<b>421.7</b>	38.2	-459.9	6.9	-13.9	14.4	9.6	68,649.50
PSD/NNSR Threshold	<b>100</b>	40	40	7	25	15	10	75,000
PSD/NNSR Permitting?	<b>Yes</b>	No	No	No	No	No	No	No

**PSD Applicability - Conclusion**

Based on the information presented in Tables 1-3, 1-4, and 1-6, GPI's proposed modification, as specified in Application No. 20207, is classified as a major modification under PSD due to the potential emissions of CO exceeding the threshold. Emissions of NO<sub>x</sub> are close to the major source threshold of 40 tpy and the applicant is requesting a NO<sub>x</sub> limit of 404.6 tpy for the new No. 3 Biomass Boiler to avoid nonattainment NSR review for PM<sub>2.5</sub>. Emissions of SAM are close to the major source threshold of 7.0 tpy and the applicant is requesting a SAM limit of 13.2 tpy for the new No. 3 Biomass Boiler to avoid PSD review for SAM. Emissions of total PM<sub>10</sub> are close to the major source threshold of 15 tpy and the applicant is requesting a PM<sub>10</sub> limit of 0.049 lb/MMBtu for the new No. 3 Biomass Boiler to avoid PSD review for PM<sub>10</sub>. Emissions of PM<sub>2.5</sub> are close to the major source threshold of 10 tpy and the applicant is requesting a PM<sub>2.5</sub> limit of 0.040 lb/MMBtu for the new No. 3 Biomass Boiler to avoid nonattainment NSR review for PM<sub>2.5</sub>.

Through its new source review procedure, EPD has evaluated GPI's proposal for compliance with State and Federal requirements. The findings of EPD have been assembled in this Preliminary Determination.

## **2.0 PROCESS DESCRIPTION**

According to Application No. 20207, GPI has proposed to expand utilization of biomass energy, allow the mill to be largely self-sufficient from an electrical power generation standpoint, and substantially reduce reliance on coal combustion.

The proposed project will include the following:

- Install a new bubbling fluidized bed (BFB) boiler (No. 3 Biomass Boiler), rated at approximately 620 MMBtu/hr to be equipped with flue gas recirculation, a baghouse, and a selective non-catalytic (SNCR) reduction system and potentially an acid gas control system (some type of sorbent injection). The No. 3 Biomass Boiler will combust biomass, natural gas, and mill wastewater treatment plant (WWTP) sludge.
- Shutdown existing No. 1 Power Boiler which combusts coal, fuel oil, and natural gas. Permanent shutdown of No. 1 Power Boiler will occur upon normal operation of No. 3 Biomass Boiler. As part of the No. 3 Biomass Boiler construction process, coal and fuel oil firing capability will be removed from the No. 1 Power Boiler prior to its complete shutdown. Once the No. 1 Power Boiler is only firing natural gas the scrubber associated with this boiler will no longer be in operation.
- Coal and fuel oil will no longer be used as fuel in the No. 2 Power Boiler with natural gas combustion capability being retained. Once the No. 2 Power Boiler is only firing natural gas the scrubber associated with this boiler will no longer be in operation. This will occur following the necessary shake-down period for the No. 3 Biomass Boiler.
- Existing biomass fuel storage and handling system will be supplemented with new conveyors to transport biomass to the No. 3 Biomass Boiler. This is treated as an insignificant activity.
- The existing bark hog tower and hammer hog and truck dump will experience throughput increases to accommodate the proposed boiler. New potential emission estimates make these units significant emission units.
- A new sand silo with fabric filtration system and associated conveyors will be installed to accommodate the BFB sand bed. This is treated as an insignificant activity.
- A new fly ash handling system and ash storage silo with fabric filtration system will be constructed to accommodate the fly ash captured by the new baghouse associated with the No. 3 Biomass Boiler. This is treated as an insignificant activity.
- New bottom ash and boiler hopper ash handling equipment will be installed to remove and store the bottom ash generated by the No. 3 Biomass Boiler. This is treated as an insignificant activity.
- Sorbent handling system and storage silo equipped with a fabric filtration system may be required. This is treated as an insignificant activity.
- A new aqueous ammonia day tank to store ammonia for usage in the SNCR. This is treated as an insignificant activity.
- New steam turbine generator rated at 40 MW. This is treated as an insignificant activity.
- New cooling tower and generator lube oil and hydraulic oil process tanks to support the new steam turbine. This is treated as an insignificant activity.
- Increase in truck traffic on paved roads.
- Reduction in actual throughput to the existing coal storage system (Source Code: B004) because of the reduced coal demand due to the shutdown of the No. 1 Power Boiler and removal of coal combustion from No. 2 Power Boiler.

The emissions from the No. 3 Biomass Boiler will route through the existing Nos. 1 and 2 Power Boilers stack. The facility proposed to install SNCR, to be relied upon as needed, to ensure NO<sub>x</sub> emissions remain below levels to avoid NSR permitting for NO<sub>x</sub> or PM<sub>2.5</sub>. The facility may also include sorbent duct injection system to provide control for hydrogen chloride (HCl) emissions, if necessary. The facility will install CO, O<sub>2</sub>, and NO<sub>x</sub> Continuous Emissions Monitoring Systems (CEMS) and a Continuous Opacity Monitoring System (COMS) to demonstrate compliance with the appropriate emission limitations.

The primary fuel of the No. 3 Biomass Boiler will be biomass, with the ability to combust wastewater treatment plant sludge. In order to ensure that the No. 3 Biomass Boiler is not classified as a Commercial and Industrial Solid Waste Incinerator (CISWI) unit, GPI will combust clean cellulosic biomass materials as defined by the U.S. EPA in 40 CFR 241.2. Natural gas will be used for startups and normal operating scenarios if there is an interruption in biomass fuel supply. The facility intends to restrict operation of the natural gas burners such that the maximum total heat input capacity is 249 MMBtu/hr. Annual natural gas usage will be limited to 10% of the maximum heat input capacity of the unit.

The new steam turbine generator will be fed by the new No. 3 Biomass Boiler. It will be utilized to generate electricity for the facility, but they may sell some of the generated electricity to the grid. The casing of the electric generator is cooled with air. Also, the electrical equipment does not contain any sulfur hexafluoride (SF<sub>6</sub>) compounds.

The GPI permit application and supporting documentation are included in Appendix A of this Preliminary Determination and can be found online at [www.georgiaair.org/airpermit](http://www.georgiaair.org/airpermit).

### **3.0 REVIEW OF APPLICABLE RULES AND REGULATIONS**

#### **State Rules**

**Georgia Rule for Air Quality Control (Georgia Rule) 391-3-1-.03(1), Construction Permit**, requires that any person prior to beginning the construction or modification of any facility which may result in an increase in air pollution shall obtain a permit for the construction or modification of such facility from the Director upon a determination by the Director that the facility can reasonably be expected to comply with all the provisions of the Act and the rules and regulations promulgated thereunder. Georgia Rule 391-3-1-.03(8)(b) continues that no permit to construct a new stationary source or modify an existing stationary source shall be issued unless such proposed source meets all the requirements for review and for obtaining a permit prescribed in Title I, Part C of the Federal Act [i.e., Prevention of Significant Deterioration of Air Quality (PSD)], and Section 391-3-1-.02(7) of the Georgia Rules (i.e., PSD).

**Georgia Rule 391-3-1-.02(2)(b), Visible Emissions**, limits the opacity of visible emissions from any air contaminant source, which is subject to some other emission limitation under 391-3-1-.02(2). The opacity of visible emissions from regulated sources may not exceed 40 percent under this general visible emission standard. It is expected that the opacity of all emissions from the proposed fly ash silo and fly ash handling units, bottom ash handling system, biomass handling units, sand storage and handling units, sorbent storage and handling units, hog tower, and proposed cooling tower will be well below 40% at all times.

Existing No. 1 Power Boiler combusts coal, recycled oil, and natural gas. GPI is transitioning the No. 1 Power Boiler to “permanent shutdown” after shake down of the No. 3 Biomass Boiler. GPI will restrict operation of the No. 1 Power Boiler to natural gas only during shakedown of the No. 3 Biomass Boiler. The No. 1 Power Boiler is subject to an emission standard in Rule 391-3-1-.02(2) and is therefore subject to the opacity standard specified by Georgia Rule 391-3-1-.02(2)(b).

Existing No. 2 Power Boiler combusts coal, recycled oil, and natural gas. GPI is transitioning the No. 2 Power Boiler to only combust natural gas. GPI will restrict operation of the No. 2 Power Boiler to natural gas only during shakedown of the No. 3 Biomass Boiler. The No. 2 Power Boiler is subject to an emission standard in Rule 391-3-1-.02(2) and is therefore subject to the opacity standard specified by Georgia Rule 391-3-1-.02(2)(b).

**Georgia Rule 391-3-1-.02(2)(c), Incinerators**, limits the particulate matter (PM) and visible emissions from incinerators. Per Georgia Rule 391-3-1-.01(hh) and incinerator is defined as . . . *all devices intended or used for the reduction or destruction of solid, liquid, or gaseous waste by burning*. Although the proposed No. 3 Biomass Boiler will combust pulp mill sludge, the main purpose of the boiler is not the destruction of solid waste. The proposed use/operation of the new No. 3 Biomass Boiler will not be subject to Georgia Rule 391-3-1-.02(2)(c) as the exemption specified in Georgia Rule 391-3-1-.02(2)(c)6.(viii) applies. Georgia Rule 391-3-1-.02(2)(c) does not apply, in part to *any vent gas incineration devices that are used as air pollution control equipment and boilers and industrial furnaces that burn waste (excluding hazardous waste) as a fuel* in accordance with Georgia Rule 391-3-1-.02(2)(c)6.(viii).

**Georgia Rule 391-3-1-.02(2)(d), Fuel-burning Equipment**, limits opacity and PM from fuel-burning equipment. This discussion covers existing Nos. 1 and 2 Power Boilers and the proposed new No. 3 Biomass Boiler.

The No. 3 Biomass Boiler meets the definition of “fuel-burning equipment” as specified in Georgia Rule 391-3-1-.01(cc). The proposed new No.3 Biomass Boiler will be capable of accommodating biomass, pulp and paper mill sludge and natural gas according to the following design constraints and/or permit conditions:

No. 3 Biomass Boiler Fuel Type	Maximum Heat Input
3 Natural Gas Startup Burners  2 Natural Gas Load Burners	45 MMBtu/hr/each for a total of 135 MMBtu/hr  122 MMBtu/hr/each for a total of 244 MMBtu/hr  For a total of 379 MMBtu/hr. See Note 2.  Note: Total NG heat input = 249 MMBtu/hr based on fuel data page in SIP Application.
Mill Sludge	28.725 MMBtu/hr based on fuel data in SIP Application
Biomass	620.14 MMBtu/hr based on fuel data in SIP Application.

The No. 3 Biomass Boiler will be unable to operate on only natural gas and mill sludge. Georgia Rule (d) specifies the following emission standards.

Pollutant	Georgia Rule (d) Standard for No. 3 Biomass Boiler (B005)	Note
PM*	0.10 lb/MMBtu as the heat input of the No. 3 Biomass Boiler is greater than 250 MMBtu/hr	See Note 1.  Applies during combustion of natural gas, mill sludge, and/or biomass.
Opacity	20% except for one six minute period per hour of not more than 27% opacity	Applies during combustion of natural gas, mill sludge, and/or biomass.
NOx	Permit Condition to restrict NG burner operation to avoid NOx limit set by Georgia Rule (d).	See Note 2  See Note 3

Note 1: Georgia Rule (d) regulates particulate matter as defined by Georgia Rules 391-3-1-.01(xx) and 391-3-1-.01(yy). Particulate matter is PM and not PM10 or PM2.5. The PM emission standard for Georgia Rule (d) includes filterable plus condensable. The applicant notes in footnote 3 of Table B-3 (4/19/2011) that CPM emissions can be as high as 0.0017 lb/MMBtu per AP-42 Section 1.6.

Note 2: Georgia Rule (d) regulates emissions of NOx from fuel-burning equipment equal to or greater than 250 MMBtu/hr when burning coal, oil, or gas separately or simultaneously. The new No. 3 Biomass Boiler will be limited to burning natural gas at a maximum heat input of 249 MMBtu/hr.

Note 3: The applicant asserts that the Georgia Rule (d) NOx limit does not apply during periods of combustion of mill sludge and/or biomass.

Existing No. 1 Power Boiler combusts coal, fuel oil, and natural gas. GPI is transitioning the No. 1 Power Boiler to “permanent shutdown” after shake down of the No. 3 Biomass Boiler. GPI will restrict operation of the No. 1 Power Boiler to natural gas only during shakedown of the No. 2 Biomass Boiler. The No. 1 Power Boiler meets the definition of “fuel-burning equipment” as specified in Georgia Rule 391-3-1-.01(cc).

The existing No. 1 Power Boiler was constructed and installed 1947-1948 and this boiler will be capable of accommodating natural gas, coal, and recycled oil according to the following design constraints and/or permit conditions:

No. 1 Power Boiler Fuel Type	Maximum Heat Input
Natural Gas	198 MMBtu/hr – Prohibit use of natural gas upon completion of shakedown period for the new No. 3 Biomass Boiler
Coal	198 MMBtu/hr – Prohibit use of coal upon initial startup of B005, where initial startup means initial startup that is connected with shakedown of the new No. 3 Biomass Boiler.
Recycle Oil	198 MMBtu/hr – Prohibit use of recycle oil upon initial startup of B005, where initial startup means initial startup that is connected with shakedown of the new No. 3 Biomass Boiler

Georgia Rule (d) specifies the following emission standards for the No. 1 Power Boiler:

Pollutant	Georgia Rule (d) Standard for No. 1 Power Boiler (B001)	Note
PM *	$P = 0.7 * (10/R)^{0.202}$ where: P= allowable weight of emissions of fly ash and/or other particulate matter in lb/MMBtu  R = heat input of fuel-burning equipment in million Btu per hour	See Note 1.  Applies during combustion of natural gas, coal, and recycle oil.

Note 1: Georgia Rule (d) regulates particulate matter as defined by Georgia Rules 391-3-1-.01(xx) and 391-3-1-.01(yy). Particulate matter is PM and not PM10 or PM2.5. The PM emission standard for Georgia Rule (d) includes filterable plus condensable. The applicant notes in footnote 3 of Table B-3 (3/22/2011) that CPM emissions can be as high as 0.0017 lb/MMBtu per AP-42 Section 1.6.

Existing No. 2 Power Boiler combusts coal, recycled oil, and natural gas. GPI is transitioning the No. 2 Power Boiler to combusting only natural gas during the shakedown of the No. 3 Biomass Boiler. The No. 2 Power Boiler meets the definition of “fuel-burning equipment” as specified in Georgia Rule 391-3-1-.01(cc).

The existing No. 2 Power Boiler was constructed and installed 1947-1948 and this boiler will be capable of accommodating natural gas, coal, and recycled oil according to the following design constraints and/or permit conditions:

No. 2 Power Boiler Fuel Type	Maximum Heat Input
Natural Gas	198 MMBtu/hr – Allow use of only natural gas upon completion of shakedown period for the new No. 3 Biomass Boiler
Coal	198 MMBtu/hr – Prohibit use of coal upon initial startup of B005, where initial startup means initial startup that is connected with shakedown of the new No. 3 Biomass Boiler
Recycle Oil	198 MMBtu/hr – Prohibit use of recycle oil upon initial startup of B005, where initial startup means initial startup that is connected with shakedown of the new No. 3 Biomass Boiler

Georgia Rule (d) specifies the following emission standards for the No. 2 Power Boiler (B002):

Pollutant	Georgia Rule (d) Standard for No. 1 Power Boiler (B001)	Note
PM *	$P = 0.7 * (10/R)^{0.202}$ where: P= allowable weight of emissions of fly ash and/or other particulate matter in lb/MMBtu  R = heat input of fuel-burning equipment in million Btu per hour	See Note 1.  Applies during combustion of natural gas, coal, and recycle oil.

Note 1: Georgia Rule (d) regulates particulate matter as defined by Georgia Rules 391-3-1-.01(xx) and 391-3-1-.01(yy). Particulate matter is PM and not PM10 or PM2.5. The PM emission standard for Georgia Rule (d) includes filterable plus condensable. The applicant notes in footnote 3 of Table B-3 (4/19/2011) that CPM emissions can be as high as 0.0017 lb/MMBtu per AP-42 Section 1.6.

**Georgia Rule 391-3-1-.02(2)(e), Particulate Emission from Manufacturing Processes**, commonly known as the process weight rate rule, limits PM emissions (filterable plus condensable) from all sources if not specified elsewhere. Georgia Rule (e) will apply to the proposed fly ash silo and handling units, bottom ash handling system, biomass handling units, new sand storage and handling units, sorbent storage and handling units, and proposed cooling tower.

The PM emissions (filterable plus condensable) are limited based on the following equations (for equipment constructed or modified after July 2, 1968), where equation (a) applies to sources with a process input rate of less than or equal to 30 ton/hour, while equation (b) applies to sources with a process input rate of more than 30 ton/hr:

$$(a) E = 4.10 * P^{0.67}$$

$$(b) E = 55.0 * P^{0.11} - 40$$

where:

E = allowable PM emission rate (lb/hr)

P = process input weight rate (ton/hr)

**Georgia Rule 391-3-1-.02(2)(g), Sulfur Dioxide**, applies to all “fuel burning” sources. The new “fuel burning” source is the No. 3 Biomass Boiler and the fossil fuel combustion is restricted to 249 MMBtu/hr. Therefore, the SO<sub>2</sub> limits specified by Georgia Rule (g)1. do not apply as the heat input rate from burning fossil fuels is less than 250 MMBtu/hr. The restricted heat input capacity of the No. 3 Biomass Boiler is approximately 620 MMBtu/hr and therefore the Georgia Rule (g) fuel sulfur content limit is 3% sulfur, by weight in accordance with Rule 391-3-1-.02(2)(g)2.

Existing No. 1 Power Boiler is being transitioned to “permanent shutdown” upon completion of shakedown period of the proposed new No. 3 Biomass Boiler. This Power Boiler will be restricted to combust only natural gas during shakedown of the new No. 3 Biomass Boiler. Existing No. 1 Power Boiler is not being “modified” per Rule 391-3-1-.01(pp). The No. 1 Power Boiler remains subject to Rule 391-3-1-.02(2)(g)2.

Existing No. 2 Power Boiler is being transitioned to combust only natural gas during shakedown of the new No. 3 Biomass Boiler. Existing No. 2 Power Boiler is not being “modified” per Rule 391-3-1-.01(pp). The No. 2 Power Boiler remains subject to Rule 391-3-1-.02(2)(g)2.

**Georgia Rule 391-3-1-.02(2)(n), Fugitive Dust**, requires facilities to take reasonable precautions to prevent fugitive dust from becoming airborne. The proposed ash silo and handling units, biomass handling units, sand storage and handling units, sorbent storage and handling units, hog tower, and cooling tower will be covered by this generally applicable rule. Georgia Rule (n) limits the percent opacity from any fugitive dust to 20%.

**Georgia Rule 391-3-1-.02(2)(gg), Kraft Pulp Mills**, provides for total reduced sulfur (TRS) emission limitations for sources at Kraft pulp mills that were in operation on September 24, 1976, and is similar to NSPS Subpart BB. The No. 3 Biomass Boiler will not be an affected source under this rule.

**Conclusion – State Rules:** The following table specifies the applicable state emission standards for the proposed project:

Emission Unit ID	Equipment	Status	Emission Standard Legal Authority
B005	No. 3 Biomass Boiler	New	391-3-1-.02(2)(d)2.(iii) 391-3-1-.02(2)(d)3. 391-3-1-.02(2)(g)2  Limit Natural Gas Fuel Usage to Avoid Rule (d) NOx Limit
B001	No. 1 Power Boiler	Phase I: Fuel Restriction During B005 Shakedown Period  Phase II: Shutdown upon operation of B005	391-3-1-.02(2)(b) 391-3-1-.02(2)(d)1.(ii) 391-3-1-.02(2)(g)2
B002	No. 2 Power Boiler	Fuel Type Restriction on Existing Unit – Not Modified	391-3-1-.02(2)(b) 391-3-1-.02(2)(d)1.(ii) 391-3-1-.02(2)(g)2
Z901	Truck Traffic	Existing – Increase in traffic	391-3-1-.02(2)(e) 391-3-1-.02(2)(n)
A911	Bark Hog Tower and Hammer Hog and Truck Dump	Existing Unit – Increase in material throughput	391-3-1-.02(2)(e) 391-3-1-.02(2)(n)
N/A	Biomass Fuel Storage and Handling System	Existing Unit – Modified	391-3-1-.02(2)(e) 391-3-1-.02(2)(n)
N/A	Sand Silo with Associated Conveyor System	New	391-3-1-.02(2)(e) 391-3-1-.02(2)(n)
N/A	Fly Ash Handling System including Ash Storage Silo	New	391-3-1-.02(2)(e) 391-3-1-.02(2)(n)
N/A	Bottom Ash and Boiler Hopper Ash Handling Equipment	New	391-3-1-.02(2)(e) 391-3-1-.02(2)(n)
N/A	Sorbent Handling System	New	391-3-1-.02(2)(e) 391-3-1-.02(2)(n)
N/A	Aqueous Ammonia Day Tank	New	391-3-1-.02(2)(b) 391-3-1-.02(2)(e)
N/A	Cooling Tower	New	391-3-1-.02(2)(e) 391-3-1-.02(2)(n)
N/A	Lube Oil Process Tank	New	391-3-1-.02(2)(e) 391-3-1-.02(2)(n)

Emission Unit ID	Equipment	Status	Emission Standard Legal Authority
N/A	Hydraulic Oil Process Tank	New	391-3-1-.02(2)(e) 391-3-1-.02(2)(n)
N/A	Coal Storage System	Existing – Reduction in actual throughput – Not Modified	391-3-1-.02(2)(e) 391-3-1-.02(2)(n)

### **Federal Rule - PSD**

The regulations for PSD in 40 CFR 52.21 require that any new major source or modification of an existing major source be reviewed to determine the potential emissions of all pollutants subject to regulations under the Clean Air Act. The PSD review requirements apply to any new or modified source which belongs to one of 28 specific source categories having potential emissions of 100 tons per year or more of any regulated pollutant, or to all other sources having potential emissions of 250 tons per year or more of any regulated pollutant. They also apply to any modification of a major stationary source which results in a significant net emission increase of any regulated pollutant.

Georgia has adopted a regulatory program for PSD permits, which the United States Environmental Protection Agency (EPA) has approved as part of Georgia's State Implementation Plan (SIP). This regulatory program is located in the Georgia Rules at 391-3-1-.02(7). This means that Georgia EPD issues PSD permits for new major sources pursuant to the requirements of Georgia's regulations. It also means that Georgia EPD considers, but is not legally bound to accept, EPA comments or guidance. A commonly used source of EPA guidance on PSD permitting is EPA's Draft October 1990 New Source Review Workshop Manual for Prevention of Significant Deterioration and Nonattainment Area Permitting (NSR Workshop Manual). The NSR Workshop Manual is a comprehensive guidance document on the entire PSD permitting process.

The PSD regulations require that any major stationary source or major modification subject to the regulations meet the following requirements:

- Application of BACT for each regulated pollutant that would be emitted in significant amounts;
- Analysis of the ambient air impact;
- Analysis of the impact on soils, vegetation, and visibility;
- Analysis of the impact on Class I areas; and
- Public notification of the proposed plant in a newspaper of general circulation

### **Definition of BACT**

The PSD regulation requires that BACT be applied to all regulated air pollutants emitted in significant amounts. Section 169 of the Clean Air Act defines BACT as an emission limitation reflecting the maximum degree of reduction that the permitting authority (in this case, EPD), on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such a facility through application of production processes and available methods, systems, and techniques. In all cases BACT must establish emission limitations or specific design characteristics at least as stringent as applicable New Source Performance Standards (NSPS).

In addition, if EPD determines that there is no economically reasonable or technologically feasible way to measure the emissions, and hence to impose and enforceable emissions standard, it may require the source to use a design, equipment, work practice or operations standard or combination thereof, to reduce emissions of the pollutant to the maximum extent practicable.

EPA's NSR Workshop Manual includes guidance on the 5-step top-down process for determining BACT. In general, Georgia EPD requires PSD permit applicants to use the top-down process in the BACT analysis, which EPA reviews. The five steps of a top-down BACT review procedure identified by EPA per BACT guidelines are listed below:

- Step 1: Identification of all control technologies;
- Step 2: Elimination of technically infeasible options;
- Step 3: Ranking of remaining control technologies by control effectiveness;
- Step 4: Evaluation of the most effective controls and documentation of results; and
- Step 5: Selection of BACT.

The following is a discussion of the applicable federal rules and regulations pertaining to the equipment that is the subject of this preliminary determination, which is then followed by the top-down BACT analysis.

### **New Source Performance Standards**

**40 CFR 60 Subpart A (General Provisions)** imposes generally applicable requirements for initial notifications, initial compliance testing, monitoring, and record keeping requirements.

**40 CFR 60 Subpart D (Standards of Performance for Fossil Fuel Fired Steam Generators for Which Construction is Commenced after August 17, 1971)** applies to steam generating units having a maximum heat input capacity in excess of 250 MMBtu/hr from fossil fuels. However, the new No. 3 Biomass Boiler is not subject to NSPS Subpart D as 40 CFR 60.40b(j) states that any unit applicable to 40 CFR 60 Subpart Db is not subject to NSPS Subpart D. The Division concurs with the applicant's findings and Subpart D is not an applicable requirement for this project.

**40 CFR 60 Subpart Da (Standards of Performance for Electric Utility Steam Generating Units for which Construction is Commenced After September 18, 1978)** applies to electric utility steam generating units with capacities greater than 250 MMBtu/hr of fossil fuel for which construction, modification, or reconstruction commenced after September 18, 1978. 40 CFR 60.41a defines an electric utility steam generating unit (EUSGU) as "constructed for the purpose of supplying more than one-third of its potential electric output capacity (PEOC) and more than 25 MW net electrical output [gross electric sales to the utility power distribution system minus purchased power] to any utility power distribution system for sale."

New No. 3 Biomass Boiler: The PEOC of the new No. 3 Biomass Boiler is 60.6 MW, making it capable of generating more than 25 MW of electricity for sale to the grid, or even one-third of its PEOC at 20.2 MW. However, that is not the purpose for this boiler. GPI will restrict burner operation to a maximum heat input capacity of 249 MMBtu/hr. Since potential fossil fuel heat input is less than 250 MMBtu/hr, the new No. 3 Biomass Boiler will not be an EUSGU under NSPS Subpart Da.

Existing No. 2 Power Boiler: The No. 2 Power Boiler is rated at 198 MMBtu/hr and was constructed in the late 1940's and has not been modified or reconstructed after September 18, 1978. Coal and fuel oil will no longer be used as fuel in the No. 2 Power Boiler with natural gas combustion capability being retained. Once the No. 2 Power Boiler is only firing natural gas the scrubber associated with this boiler will no longer be in operation. This will occur following the necessary shake-down period for the No. 3 Biomass Boiler. The No. 2 Power Boiler is not being "modified" per NSPS definition of "modification" found in 40 CFR 60.2. In addition, the No. 2 Power Boiler is not potentially subject to NSPS Da as it has a maximum heat input of less than 250 MMBtu/hr.

**Existing No. 1 Power Boiler:** The No. 1 Power Boiler is rated at 198 MMBtu/hr and was constructed in the late 1940's and has not been modified or reconstructed after September 18, 1978. Coal and fuel oil will no longer be used as fuel in the No. 1 Power Boiler with natural gas combustion capability being retained during shakedown of the new No. 3 Biomass Boiler. Once the No. 1 Power Boiler is only firing natural gas the scrubber associated with this boiler will no longer be in operation. This will occur following the necessary shake-down period for the No. 3 Biomass Boiler. The No. 1 Power Boiler is not being "modified" per NSPS definition of "modification" found in 40 CFR 60.2. In addition, the No. 2 Power Boiler is not potentially subject to NSPS Da as it has a maximum heat input of less than 250 MMBtu/hr.

The Division concurs with the applicant's findings and 40 CFR 60 Subpart Da is not an applicable requirement for this project.

**40 CFR 60 Subpart Db (Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units)** provides standards of performance for steam generating units with capacities greater than 100 MMBtu/hr for which construction, modification, or reconstruction commenced after June 19, 1984. As noted earlier, the Nos. 1 and 2 Power Boilers are not being "modified" per the NSPS definition of "modification" found in 40 CFR 60.2. Thus, the Nos. 1 and 2 Power Boilers are not potentially subject to Subpart Db.

The new No. 3 Biomass Boiler will be constructed after 1984, will have a heat input capacity greater than 100 MMBtu/hr, and will generate steam. The No. 3 Biomass Boiler will be subject to the more stringent requirements of the standard as it is being constructed post-February 2005. The following table presents a summary of the potentially applicable requirements of NSPS Subpart Db for the proposed boiler.

Pollutant	Limitation	Monitoring	Notes
PM	0.030 lb/MMBtu	PM CEM (PS-11) <u>or</u> COMs (PS-1)	Requirements per 40 CFR 60.43b(f)-(h). The limitations apply at all times except during startup, shutdown, or malfunction.  <b>Applicant proposes to install and operate a COMs and conduct yearly tests for filterable PM.</b>
Opacity	20% except for one 6-minute period per hour of not more than 27%	Refer to PM Req'ts	<b>Applicant proposes to install and operate a COMs</b>
SO <sub>2</sub> – Natural Gas	NA	NA	Exemption from limit per 40 CFR 60.42b(k)(2)
SO <sub>2</sub> – natural gas mixed with fuels with potential SO <sub>2</sub> ≤ 0.32 lb/MMBtu	NA	Fuel records, site-specific weekly fuel analysis – 40 CFR 60.49b(r)	Exemption from limit per 40 CFR 60.42b(k)(2)  <b>Applicant anticipates this option will apply. Proposed No. 3 Biomass Boiler will not be able to combust natural gas with mill sludge only.</b>

Pollutant	Limitation	Monitoring	Notes
SO <sub>2</sub> – natural gas mixed with fuels with potential uncontrolled SO <sub>2</sub> > 0.32 lb/MMBtu	0.20 lb/MMBtu	SO <sub>2</sub> CEM (PS-2, PS-3)	Per 40 CFR 60.42b(k)(1), this limitation applies when combusting “coal, oil, natural gas, a mixture of these fuels, or a mixture of these fuels with any other fuels.” 30-day rolling average.  <b>Applicant does not anticipate utilizing this option.</b>
NO <sub>x</sub> – 10% fossil fuel annual capacity limit	NA	Fuel records	Capacity limit applies to coal, oil, and natural gas.  <b>Applicant anticipates requesting a capacity factor limitation of 10%.</b>
NO <sub>x</sub> – no fossil fuel annual capacity limit	0.20 lb/MMBtu	NO <sub>x</sub> CEMS	Limitation is on a 30-day rolling average  <b>Applicant does not anticipate utilizing this option.</b>

GPI will be required to develop a site-specific fuel analysis plan for review and approval at least 60 days prior to demonstrating compliance. The plan must include a minimum initial requirement of weekly testing and each analysis report must demonstrate the potential emissions rate of the representative fuel mixture, the methodology employed, and the ratio of fuels in the fuel mixture in accordance with 40 CFR 60.45b(k), and 60 .49b(r)(2).

**40 CFR 60 Subpart E (Incinerators):** The applicant asserts that the proposed new No. 3 Biomass Boiler will not combust a “solid waste” as defined in 40 CFR 60.51(b). The Division concurs with the applicant’s findings and Subpart E is not an applicable requirement for this project.

**40 CFR 60 Subpart Eb (Large Municipal Waste Combustors):** The applicant asserts that the proposed new No. 3 Biomass Boiler will not combust any municipal solid waste and thus will not be subject to this subpart. The Division concurs with the applicant’s findings and Subpart Eb is not an applicable requirement for this project.

**40 CFR 60 Subpart O (Sewage Treatment Plants):** The applicant asserts that the new No. 3 Biomass Boiler will not combust any municipal sewage sludge and thus will not be subject to this subpart. The Division concurs with the applicant’s findings and Subpart O is not an applicable requirement for this project.

**40 CFR 60 Subpart BB (Kraft Pulp Mills):** The applicant asserts that the new No. 3 Biomass Boiler will not be used for the combustion of any total reduced sulfur-containing (TRS) process gases produced at the Mill and thus will not be subject to this subpart. The Division concurs with the applicant’s findings and Subpart BB is not an applicable requirement for this project.

**40 CFR 60 Subpart GG (Stationary Gas Turbines):** The applicant asserts that the new steam turbine is not a combustion turbine, and thus will not be subject to this subpart. The Division concurs with the applicant’s findings and Subpart GG is not an applicable requirement for this project.

**40 CFR 60 Subpart OOO (Standards of Performance for Nonmetallic Mineral Processing Plants):**

This subpart establishes requirements for affected facilities being constructed on or after August 31, 1998 (note separate requirements apply to sources constructed, reconstructed or modified after April 22, 2008). An affected facility in this subpart is defined as a facility that uses any combination of equipment to crush or grind any nonmetallic material.

Presently, GPI does not anticipate that the sorbent injection system will include any crushing or grinding operations; rather GPI will purchase sorbent sized appropriately for the injection system. In this scenario, the affected facility definition under Subpart OOO will not be met, and this Subpart will not apply. Should GPI opt to pursue a system with grinding, applicability of Subpart OOO will be reassessed and Georgia EPD notified of possible changes. The Division concurs with these findings.

**40 CFR 60 Subpart AAAA (Small Municipal Waste Combustion Units):** The applicant asserts that the new No. 3 Biomass Boiler will not combust any municipal solid waste and thus will not be subject to this subpart. The Division concurs with the applicant's findings and Subpart AAAA is not an applicable requirement for this project.

**40 CFR 60 Subpart CCCC (Commercial and Industrial Solid Waste Incinerators):** The applicant asserts that the fuels to be fired in the No. 3 Biomass Boiler will not meet the definition of solid waste as defined under 40 CFR 241. The facility is accepting, as a permit requirement, a definition for biomass as clean cellulosic biomass, and/or cellulosic biomass (virgin wood) to be fired in the No. 3 Biomass Boiler. The Division concurs with the applicant's findings and Subpart CCCC is not an applicable requirement for this project.

**40 CFR 60 Subpart EEEE (Other Solid Waste Incineration Units):** The applicant asserts that the new No. 3 Biomass Boiler will not combust any municipal solid waste and thus will not be subject to this subpart. The Division concurs with the applicant's findings and Subpart AAAA is not an applicable requirement for this project.

**40 CFR 60 Subpart KKKK (Stationary Combustion Turbines):** The applicant asserts that the new steam turbine is not a combustion turbine, and thus will not be subject to this subpart. The Division concurs with the applicant's findings and Subpart KKKK is not an applicable requirement for this project.

**Federal NSPS Rules – Conclusion:** The following table specifies the federal requirements for this project.

Emission Unit ID	Equipment	Status	Emission Standard Legal Authority
B005	No. 3 Biomass Boiler	New	PM Filterable Limit of 0.030 lb/MMBtu for NSPS Db  Limit Capacity Factor To Avoid NOx Limit in NSPS Db  <b>Applicant wants to avoid CISWI rule.</b>
B001	No. 1 Power Boiler	Phase I: Fuel Restriction During B005 Shakedown Period  Phase II: Shutdown upon operation of B005	No new federal NSPS rules will apply.
B002	No. 2 Power Boiler	Fuel Type Restriction on Existing Unit – Not Modified	No new federal NSPS rules will apply

Emission Unit ID	Equipment	Status	Emission Standard Legal Authority
Z901	Truck Traffic	Existing – Increase in traffic	No new federal NSPS rules will apply
A911	Bark Hog Tower and Hammer Hog and Truck Dump	Existing Unit – Increase in material throughput	No new federal NSPS rules will apply
N/A	Sand Silo with Associated Conveyor System	New	No new federal NSPS rules will apply
N/A	Fly Ash Handling System including Ash Storage Silo	New	No new federal NSPS rules will apply
N/A	Bottom Ash and Boiler Hopper Ash Handling Equipment	New	No new federal NSPS rules will apply
N/A	Sorbent Handling System	New	No new federal NSPS rules will apply.
N/A	Aqueous Ammonia Day Tank	New	No new federal NSPS rules will apply
N/A	Cooling Tower	New	No new federal NSPS rules will apply
N/A	Lube Oil Process Tank	New	No new federal NSPS rules will apply
N/A	Hydraulic Oil Process Tank	New	No new federal NSPS rules will apply
N/A	Biomass Fuel Storage and Handling System	Existing Unit – Modified	No new federal NSPS rules will apply
N/A	Coal Storage System	Existing – Reduction in actual throughput – Not Modified	No new federal NSPS rules will apply

**National Emissions Standards For Hazardous Air Pollutants**

**Part 61 Subpart A (General Provisions)** imposes generally applicable requirements for initial notifications, initial compliance testing, monitoring, and record keeping requirements.

**Part 61 Subpart E (National Emission Standard for Mercury)** limits mercury emissions from several types of operations including combustion of WWTP sludge. The new No.3 Biomass Boiler (B005) will combust sludge from the mills’ WWTP. Accordingly, the boiler will be subject to the requirements of 40 CFR Part 61 Subpart E. The Division concurs with the applicant’s findings.

Pollutant	Limitation	Monitoring
Mercury - Hg	7.1 pounds per 24-hour period per 40 CFR 61.52(b)	Initial Stack Testing or sludge sampling within 90 days of startup.  <b>The applicant intends to conduct sludge test sampling per the requirements of 40 CFR 61.54.</b>

**Part 61 Subpart M (National Emission Standards for Asbestos)** applies to various industrial facilities that handle, process, or manufacture asbestos. The only Subpart M provision potentially applicable to the Mill, applies to the owner or operator of a demolition or renovation activity where asbestos may be disturbed. GPI does not anticipate any activities involving asbestos as part of the proposed construction activities. The Division concurs with the applicant's findings and 61 Subpart M is not an applicable requirement for this project.

**Part 63 Subpart A (General Provisions)** imposes generally applicable requirements for initial notifications, initial compliance testing, monitoring, and record keeping requirements. This regulation contains national emission standards for hazardous air pollutants (NESHAP) established pursuant to section 112 of the Act as amended November 15, 1990. These standards regulate specific categories of stationary sources that emit (or have the potential to emit) one or more hazardous air pollutants listed in this part pursuant to section 112(b) of the Act. The standards in this part are independent of NESHAP contained in 40 CFR Part 61. The NESHAP in part 61 promulgated by signature of the Administrator before November 15, 1990 (i.e., the date of enactment of the Clean Air Act Amendments of 1990) remain in effect until they are amended, if appropriate, and added to 40 CFR Part 63 [40 CFR 63.1(a)(1) and (2)]. No emission standard or other requirement established under 40 CFR Part 63 shall be interpreted, construed, or applied to diminish or replace the requirements of a more stringent emission limitation or other applicable requirement established by the Administrator pursuant to other authority of the Act (section 111, part C or D or any other authority of this Act), or a standard issued under State authority. The Administrator may specify in a specific standard under this part that facilities subject to other provisions under the Act need only comply with the provisions of that standard [40 CFR 63.1(a)(3)]. GPI is an existing facility with applicable units subject to this regulation.

**Part 63 Subpart B, 112(g) (Case-by-Case MACT)** Section 112(g) of the 1990 Clean Air Act Amendments is known as the case-by-case MACT. The effective date of the NESHAP regulating boilers (Subpart DDDDD) has been stayed. Thus, at this time, case-by-case MACT is potentially applicable to new boilers. Case-by-case MACT is applicable to newly constructed major sources of HAP emissions. "Construct a major source" is defined as follows per Subpart B:

... (2) To fabricate, erect, or install at any developed site a new process or production unit which in and of itself emits or has the potential to emit 10 tons per year of any HAP or 25 tons per year of any combination of HAP, ....

Therefore, to be subject to the case-by-case MACT requirement, HAP emissions from the No. 3 Biomass Boiler alone must be major. As discussed previously in this application, anticipated HAP emissions from the No. 3 Biomass Boiler do not exceed the 10/25 tpy HAP major source thresholds and the facility is accepting limits as such. Therefore, case-by-case MACT does not apply to the proposed boiler. The Division concurs with the applicant's findings and 63 Subpart B, 112(g) is not an applicable requirement for this project.

**Part 63 Subpart Q (NESHAP for Industrial Process Cooling Towers)** applies to cooling towers operating with chromium-based water treatment chemicals that are located at facilities that are major sources of hazardous air pollutants (HAPs). The proposed new cooling tower water treatment chemicals will not be chromium based, and hence the proposed new cooling tower will not be subject to this subpart. The Division concurs with the applicant's findings and 63 Subpart Q is not an applicable requirement for this project.

**Part 63 Subpart S (NESHAP from the Pulp and Paper Industry)** requires that various pulping process air emissions and process condensate emissions at pulp mills that are major HAP sources be collected and treated. The Macon Mill is a major source of HAP emissions, and therefore, is subject to the NESHAP Subpart S regulations prior to construction of this project.

The proposed project is not subject to NESHAP Subpart S because GPI does not intend to use the proposed No. 3 Biomass Boiler for combustion of regulated process gases. The Division concurs with the applicant’s findings and 63 Subpart S is not an applicable requirement for this project.

**Part 63 Subpart MM (NESHAP for Chemical Recovery Combustion Sources at Kraft, Soda, Sulfite, and Stand-Alone Semichemical Pulp Mills)** requires the reduction of HAP emissions from the chemical recovery combustion sources at pulp mills that are major HAP sources. The proposed project is not subject to NESHAP Subpart MM because biomass boilers are not affected sources under Subpart MM. The Division concurs with the applicant’s findings and 63 Subpart MM is not an applicable requirement for this project.

**Part 63 Subpart DDDDD (NESHAP for Industrial-Commercial-Institutional Boilers and Process Heaters)** applies to steam generating units at a major source for HAP. New boilers must be in compliance upon startup; however, at the time of this Preliminary Determination, the compliance date for the rule was stayed. The proposed No. 3 Biomass Boiler will have a heat input capacity greater than 100 MMBtu/hr, and will generate steam. As of July 1, 2011 the following table represents the limits and monitoring with which the facility would have to comply if the compliance date was not stayed.

Pollutant	Limitation	Monitoring
PM filterable	0.0011 lb/MMBtu	COMs
Opacity	20% except for one 6-minute period per hour of not more than 27%	Refer to PM Req’ts
CO	260 ppm, 3% O2 on a dry basis	1 time stack testing and O2 monitoring
HCl	0.0022 lb/MMBtu	Sorbent injection
Mercury	3.50E-06 lb/MMBtu	Monthly fuel analysis
Dioxins/Furans	0.02 ng/dscm (teq) corrected to 7% O2	1 time stack testing and O2 monitoring

**40 CFR 63 Subpart YYYY (NESHAP for Stationary Combustion Turbines):** The applicant asserts that the new steam turbine is not a combustion turbine, and thus will not be subject to this subpart. The Division concurs with the applicant’s findings and 63 Subpart YYYY is not an applicable requirement for this project.

**Federal Part 61 and Part 63 Rules – Conclusion:** The following table specifies the federal requirements for this project.

Emission Unit ID	Equipment	Status	Emission Standard Legal Authority
B005	No. 3 Biomass Boiler	New	Part 61 Subpart E upon startup Part 63 Subpart DDDDD upon compliance date
B001	No. 1 Power Boiler	Phase I: Fuel Restriction During B005 Shakedown Period  Phase II: Shutdown upon operation of B005	No new federal Part 61 or Part 63 rule applies.
B002	No. 2 Power Boiler	Fuel Type Restriction on Existing Unit – Not Modified	No new federal Part 61 or Part 63 rule applies.
Z901	Truck Traffic	Existing – Increase in traffic	No new federal Part 61 or Part 63 rule applies.

<b>Emission Unit ID</b>	<b>Equipment</b>	<b>Status</b>	<b>Emission Standard Legal Authority</b>
A911	Bark Hog Tower and Hammer Hog and Truck Dump	Existing Unit – Increase in material throughput	No new federal Part 61 or Part 63 rule applies.
N/A	Sand Silo with Associated Conveyor System	New	No new federal Part 61 or Part 63 rule applies.
N/A	Fly Ash Handling System including Ash Storage Silo	New	No new federal Part 61 or Part 63 rule applies.
N/A	Bottom Ash and Boiler Hopper Ash Handling Equipment	New	No new federal Part 61 or Part 63 rule applies.
N/A	Sorbent Handling System	New	No new federal Part 61 or Part 63 rule applies.
N/A	Aqueous Ammonia Day Tank	New	No new federal Part 61 or Part 63 rule applies.
N/A	Cooling Tower	New	No new federal Part 61 or Part 63 rule applies.
N/A	Lube Oil Process Tank	New	No new federal Part 61 or Part 63 rule applies.
N/A	Hydraulic Oil Process Tank	New	No new federal Part 61 or Part 63 rule applies.
N/A	Biomass Fuel Storage and Handling System	Existing Unit – Modified	No new federal Part 61 or Part 63 rule applies.
N/A	Coal Storage System	Existing – Reduction in actual throughput – Not Modified	No new federal Part 61 or Part 63 rule applies.

### **State and Federal – Startup and Shutdown and Excess Emissions**

Excess emission provisions for startup, shutdown, and malfunction are provided in Georgia Rule 391-3-1-.02(2)(a)7. Excess emissions from the No. 3 Biomass Boiler, biomass fuel storage and handling system, bark hog tower and hammer hog truck dump, sand silo and associated conveyor system, fly ash handling system including ash storage silo, bottom ash and boiler hopper ash handling equipment, sorbent handling system, aqueous ammonia day tank, cooling tower, lube oil process tank, and hydraulic oil process tank associated with the proposed project would most likely results from a malfunction of the associated control equipment. The facility cannot anticipate or predict malfunctions. However, the facility is required to minimize emissions during periods of startup, shutdown, and malfunction.

The facility has proposed a secondary BACT limit to address periods of startup, shutdown, and malfunction for CO emissions. This BACT limit is mass-based on a tons-per-year basis, with compliance determined via CEMS.

### **Federal Rule – 40 CFR 64 – Compliance Assurance Monitoring**

The requirements of 40 CFR 64 apply to a pollutant-specific emissions unit at a major source that is required to obtain a Part 70 or 71 permit if the unit satisfies all of the following criteria: (1) The unit is subject to an emission limitation or standard for the applicable regulated air pollutant (or a surrogate thereof), other than an emission limitation or standard that is exempt under 40 CFR 64.2(b)(1); (2) The unit uses a control device to achieve compliance with any such emission limitation or standard; (3) The unit has potential pre-control device emissions of the applicable regulated air pollutant that are equal to or greater than 100 percent of the amount, in tons per year, required for a source to be classified as a major source. “Potential pre-control device emissions” has the same meaning as “potential to emit” as defined in 40 CFR 64.1, except that emission reductions achieved by the applicable control device are not taken into account [40 CFR 64.2(a)].

The proposed No. 3 Biomass Boiler has pre-controlled emissions greater than 100 tpy for NO<sub>x</sub>, filterable PM, and total PM<sub>10</sub>/PM<sub>2.5</sub> and will be subject to emission limits for these pollutants. Pre-controlled emissions of HCl will possibly be greater than 10 tpy, the single HAP major source threshold. If required, HCl emissions will be reduced via a sorbent injection system. SNCR will be used to reduce NO<sub>x</sub> emissions and a baghouse will be used to control predominately filterable PM, with possible reductions of total PM<sub>10</sub>/PM<sub>2.5</sub> emissions. As such, the boiler will require CAM Plans specific to NO<sub>x</sub>, filterable PM, and total PM<sub>10</sub>/PM<sub>2.5</sub>, unless a specific exemption under 40 CFR 64.2(b) is met. None of the other NSR-regulated pollutants utilize a control device to meet an emission limit.

40 CFR 64.2(b) lists a number of exemptions from CAM applicability. Key exemptions considered include:

- Emission limits proposed by U.S. EPA after November 15, 1990 under Sections 111 or 112 of the Clean Air Act.
- Emission limits or standards for which a Title V operating permit specifies a continuous compliance demonstration method (i.e., continuous parameter, opacity, or emissions monitoring)

Any limits for the No. 3 Biomass Boiler that are exclusively from post-November 15, 1990 NSPS or NESHAP limits are excluded from CAM applicability (i.e., NSPS Subpart Db filterable PM limit for post-2005 units). However, additional PM related limit(s) will apply based on Georgia Rules for Air Quality Control and/or NSR-avoidance, and such limits are not excluded from CAM applicability. However, GPI will be utilizing continuous parameter monitoring systems, a COMS, to ensure compliance with the filterable PM and total PM<sub>10</sub>/PM<sub>2.5</sub> limits, also meeting the continuous compliance demonstration method exemption. Therefore, the No. 3 Biomass Boiler will be exempt from CAM requirements for filterable PM and total PM<sub>10</sub>/PM<sub>2.5</sub>.

GPI is proposing to utilize a NO<sub>x</sub> CEMS to demonstrate compliance with the proposed NO<sub>x</sub> limit; usage of the CEMS will be included in the Title V operating permit, meeting the continuous compliance demonstration method exemption.

If duct sorbent injection is required to ensure HCl emissions remain below the required 10 tpy limit, GPI will be using a continuous parameter monitoring system to monitor the sorbent injection rate, meeting the continuous compliance demonstration method exemption. If duct sorbent injection is not used, CAM will not apply since a control device is not employed for HCl.

All other new units at the Macon Mill will emit post-controlled emissions less than the major source threshold(s) and/or do not use a control device as defined by the CAM regulations (note devices used for pneumatic transfer are considered inherent to the operation of the emission unit, not control devices, per the CAM definition of a control device). It is possible some of the new biomass handling system units will have pre-controlled PM emissions of greater than the major source threshold. However, final designs of the baghouses have not been completed. Upon design completion and installation of the baghouses, GPI will evaluate CAM applicability for these sources as part of the next Title V operating permit renewal application.

In the 2005 Title V operating permit renewal application, GPI documented the inapplicability of CAM to the existing Nos. 1 and 2 Power Boilers due to the continuous scrubber parameter monitoring. The inapplicability will remain in effect for the No. 2 Power Boiler upon removal of the coal and fuel oil combustion capabilities as part of this proposed project as the unit will no longer employ a control device.

### **Federal Rule – 40 CFR 72, 73, 75, 76, and 77 – Acid Rain**

40 CFR 73.10, Phase II of the Acid Rain Program applies to large, fossil fuel-fired combustion sources that drive generators for the purposes of generating electricity for sale. While GPI does not currently generate electricity for sale, sales to the grid are being contemplated following completion of this project.

The facility has several existing cogeneration sources, including No. 2 Biomass Boiler, Nos. 1 and 2 Power Boilers, and the No. 3 Recovery Boiler, all of which have the ability to combust fossil fuel. No. 2 Biomass Boiler and No. 1 and 2 Power Boilers were constructed prior to November 15, 1990 and the No. 3 Recovery Boiler was post-November 15, 1990. 40 CFR 72.6(b)(4) states:

A cogeneration facility which:

- (i) For a unit that commenced construction on or prior to November 15, 1990, was constructed for the purpose of supplying equal to or less than one-third its potential electrical output capacity or equal to less than 219,000 MWe-hrs actual electric output on an annual basis to any utility power distribution system for sale (on a gross basis).
- (ii) For units which commenced construction after November 15, 1990, supplies equal to or less than one-third its potential electrical output capacity or equal to or less than 219,000 MWe-hrs actual electric output on an annual basis to any utility power distribution system for sale (on a gross basis)

Since the No. 2 Biomass Boiler and No. 1 and 2 Power Boilers were constructed for the purpose of supplying steam and electricity for the mill, and have never sold to the grid, they are exempt as cogeneration units under 40 CFR 72.6(b)(4)(i).

The No. 3 Recovery Boiler and other source feed a common multi-header steam system to distribute steam to the 4 existing steam turbines at the Mill. As established in the U.S. EPA “Acid Rain Guidelines” for a multi-headered system, if the ratio of the total generator nameplate capacity to the combined potential electrical output capacity (PEOC) is less than one-third of the PEOC, the units feeding the multi-headered system are generally not affected units under the Acid Rain Program. The table below provides the estimated combined PEOC and the resulting comparison to the total nameplate capacity for the existing units.

**COMBINED HEADER PEOC ESTIMATE**

Unit	Heat Input Capacity (MMBtu/hr)	Individual PEOC <sup>1</sup> (MWe)	1/3 of Individual Unit PEOC		Combined PEOC <sup>2</sup> (MWe)	Total Turbine Rating <sup>3</sup> (MWe)	1/3 of Combined PEOC	
			(MWe)	(MWe-hr)			(MWe)	(MWe-hr)
No. 1 Power Boiler	198	19.3	6.4	56,466	192	45	64.0	560,672
No. 2 Power Boiler	198	19.3	6.4	56,466				
No. 3 Recovery Boiler	1,050	102.5	34.2	299,443				
No. 2 Biomass Boiler	520	50.8	16.9	148,296				

1. PEOC is estimated per 40 CFR 72.2 and Appendix D to 40 CFR Part 72:

$$PEOC = \left( \frac{Q}{3} \right) \left( \frac{10^6 \text{ Btu}}{\text{MMBtu}} \right) \left( \frac{1 \text{ kW} - \text{hr}}{3,413 \text{ Btu}} \right) \left( \frac{1 \text{ MW}}{1,000 \text{ kW}} \right)$$

where Q represents the Maximum Designed Heat Input (MMBtu/hr).

2. Combined PEOC was estimated per guidance from *Do the Acid Rain SO<sub>2</sub> Regulations Apply to You? A Guide for Utilities and Other Electricity Generators*,” EPA Office of Air and Radiation, Acid Rain Division, #430-R-94-002, February 1994, pg. 13.

3. Based on total of the existing 4 turbines as a common steam header and electricity distribution system are used.

As shown above, one-third of the combined PEOC exceeds the total turbine electricity generating capacity. Accordingly, the multi-header system is not capable of supplying more than one-third of its PEOC for sale to the utility grid. Accordingly, the No. 3 Recovery Boiler is also not subject to the requirements of the ARP as it meets the cogeneration unit exemption per 40 CFR 72.6(b)(4)(ii).

The No. 3 Biomass Boiler, which will be capable of combusting a fossil fuel, will provide dedicated steam to the proposed 40 MW steam turbine as well as process steam. The PEOC for the proposed No. 3 Biomass Boiler is 60.6 MWe; making it capable of generating more than 219,000 MWe-hr of electricity for sale to the grid. One-third of the PEOC is 20.2 MWe (176,952 MWe-hr). As it is serving a turbine generator with a 40 MW nameplate capacity, it is capable of generating more than one-third of its PEOC for sale to the grid. Accordingly, GPI is requesting a direct electricity sales limitation for the proposed No. 3 Biomass Boiler of 219,000 MWe-hr such that the unit qualifies for the cogeneration unit exemption. As electricity passing to the grid cannot presently be traced back to a specific generating unit, the proposed direct electricity sales limit is proposed as a facility-wide limit.

**Federal Rule – Clean Air Interstate Rule (CAIR) – 40 CFR 96**

On May 12, 2005, EPA issued CAIR to make reductions in emissions of NOx and SO2 by utilizing an emissions trading program. On July 11, 2008, the District of Columbia (D.C.) Circuit Court of Appeals vacated CAIR in its entirety. On November 17, 2008 the United States EPA filed a reply in support of its petition for rehearing in the Clean Air Interstate Rule case. On December 28, 2008, the D.C. Circuit Court of Appeals has remanded the CAIR rule without vacatur. Therefore, this rule will remain in place until EPA issues a new rule to replace CAIR in accordance with the July 11, 2008 decision. In August 2010, EPA has proposed the new Transport CAIR Rule (also known as TR – 40 CFR 97) with compliance dates of January 1, 2012 and January 1, 2014, for the first and second phases, respectively. However, this new rule is not promulgated yet.

In general, a fossil fuel-fired emissions unit that serves a generator with a nameplate capacity of 25 MW or greater and sells any electricity is subject to CAIR. However, if a unit qualifies as a cogeneration unit, it may sell up to one-third of the unit’s PEOC, where PEOC is defined in an identical manner as under the ARP. However, there is a major distinction in the definition of a cogeneration unit under the ARP and under CAIR. Under ARP, a cogeneration unit is determined by what it is capable of doing. Under CAIR, a cogeneration unit is instead defined based on what a unit actually does. Therefore, any limits taken to avoid ARP applicability also ensure the CAIR is avoided.

The electricity limitation proposed for the No. 3 Biomass Boiler may not actually be required for avoidance of CAIR requirements. The original definitions for a cogeneration unit did not originally include the biomass exemption; in October 2007, this definition was amended to specifically exclude biomass from the energy efficiency determination. Given this biomass exclusion, the proposed No. 3 Biomass Boiler would potentially meet the cogeneration exemption included in CAIR.

### **Greenhouse Gas (GHG) Reporting Program**

In response to the FY2008 Consolidated Appropriations Act (H.R. 2764; Public Law 110-161), EPA issued the Mandatory Reporting of Greenhouse Gases Rule (74 FR 5620) which requires reporting of greenhouse gas (GHG) data and other relevant information from large sources and suppliers in the United States. The purpose of this rule is to collect accurate and timely GHG data to inform future policy decisions. In general, the Rule is referred to as 40 CFR Part 98. Implementation of Part 98 is referred to as the Greenhouse Gas Reporting Program (GHGRP). The GHGRP is not an applicable requirement for GPI's Title V amendment and is therefore not included.

### **Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule**

On June 3, 2010 (75 FR 31514-31608), the U.S. EPA issued a final rule that establishes an approach to addressing greenhouse gas emissions from stationary sources under the Clean Air Act (CAA) permitting programs. This final rule sets thresholds for GHG emissions that define when permits under the New Source Review PSD and title V Operating Permit programs are required for new and existing industrial facilities.

The CAA permitting program emissions thresholds for criteria pollutants such as lead, sulfur dioxide and nitrogen dioxide, are 100 and 250 tpy. While these thresholds are appropriate for criteria pollutants, they are not feasible for GHGs because GHGs are emitted in much higher volumes.

The final rule addresses emissions of a group of six GHGs:

1. Carbon dioxide (CO<sub>2</sub>)
2. Methane (CH<sub>4</sub>)
3. Nitrous oxide (N<sub>2</sub>O)
4. Hydrofluorocarbons (HFCs)
5. Perfluorocarbons (PFCs)
6. Sulfur hexafluoride (SF<sub>6</sub>)

Some of these GHGs have a higher global warming potential than others. To address these differences, the international standard practice is to express GHGs in carbon dioxide equivalents (CO<sub>2</sub>e). Emissions of gases other than CO<sub>2</sub> are translated into CO<sub>2</sub>e by using the gases' global warming potentials. Under this rule, EPA is using CO<sub>2</sub>e as the metric for determining whether sources are covered under permitting programs. Total GHG emissions will be calculated by summing the CO<sub>2</sub>e emissions of the six aforementioned constituent GHGs.

EPA will phase in the CAA permitting requirements for GHGs in two initial steps. Step 1 pertains only to sources currently subject to the PSD permitting program (i.e., those that are newly constructed or modified in a way that significantly increases emissions of a pollutant other than GHGs) would be subject to permitting requirements for their GHG emissions under PSD.

For these projects, only GHG increases of 75,000 tpy or more of total GHG, on a CO<sub>2</sub>e basis, would need to determine the Best Available Control Technology (BACT) for their GHG emissions. Similarly for the operating permit program, only sources currently subject to the program (i.e., newly constructed or existing major sources for a pollutant other than GHGs) would be subject to title V requirements for GHG. During this time, no sources would be subject to Clean Air Act permitting requirements due solely to GHG emissions.

Step 1 of this final rule took effect on January 2, 2011. Based on a ruling signed by U.S. EPA on July 1, 2011 and published in the Federal Register on July 20, 2011 (Vol. 76, No. 139, page 43490), GHG permitting requirements for CO<sub>2</sub> emissions from biomass-fired and other biogenic sources are deferred for a period of three years. During the next three years, the EPA will conduct a “study to consider technical issues that must be resolved in order to account for biogenic CO<sub>2</sub> emissions in ways that are scientifically sound and also manageable in practice.” EPA will also develop “a final rule by the conclusion of the three year deferral period regarding how biogenic CO<sub>2</sub> emissions should be treated and accounted for in PSD and Title V permitting based on the feedback from the scientific and technical review.”

Currently, CO<sub>2</sub>e emissions from the GPI PSD project do not exceed the 75,000 tpy CO<sub>2</sub>e threshold outlined in Step 1 of the GHG Emissions Tailoring Rule, based on the biogenic emissions exemption and Best Available Control Technology (BACT) review is not required for GHG emissions.

## **4.0 CONTROL TECHNOLOGY REVIEW**

The proposed project will result in emissions that are significant enough to trigger PSD review for CO emissions.

### **No. 3 Biomass Boiler - Background**

The No. 3 Biomass Boiler is a bubbling fluidized bed boiler capable of firing biomass, natural gas, and mill wastewater treatment plant sludge at an approximate heat input rating of 620 MMBtu/hr.

### **No. 3 Biomass Boiler – CO BACT Emissions**

Carbon Monoxide (CO) from the biomass boilers is a by-product of incomplete combustion of carbon in the fuel source. Conditions leading to incomplete combustion include insufficient oxygen availability, poor fuel/air mixing, reduced combustion temperature, reduced combustion gas residence time, and load reduction. Control of CO is usually accomplished by providing proper fuel residence time and proper combustion conditions (excess air). However, factors to reduce NO<sub>x</sub> emissions can lead to an increase in CO emissions. Carbon monoxide is often used as a measure of combustion efficiency and often as a surrogate for “good combustion.”

In Application No. 20207, the applicant performed the 5-step BACT analysis for the CO emissions from the biomass boiler. The brief summary of the applicant’s BACT analysis is as follows:

#### Applicant’s Proposal

##### *Step 1: Identify all control technologies*

The applicant identified and performed detailed discussion of the following CO control technologies for the new Biomass Boiler:

- Oxidation Catalyst
- Good Design and Operating Practices

Please refer to page 6-12 of Application No. 20207 – Volume I dated August 10, 2011 for details on the CO control technologies.

##### *Step 2: Eliminate technically infeasible option*

The applicant evaluated technical feasibility of all control technologies that are stated in step 1 and determined that all control technologies were technically feasible. Please refer to page 6-12 of Application No. 20207 – Volume I dated August 10, 2011.

##### *Step 3: Ranking the Remaining Control Technologies by Control Effectiveness*

The applicant has provided a ranking of the CO control technologies that are technically feasible for this project, as listed in the following table 4-1:

**Table 4-1: Remaining CO Control Technology Ranking**

<b>Rank</b>	<b>Control Technology</b>	<b>Expected Emissions</b>	<b>Control Efficiency</b>
1	Oxidation Catalyst	0.075 lb/MMBtu	50%
2	Good Design and Operating Practices	0.15 lb/ MMBtu	Baseline

*Step 4: Evaluating the Most Effective Controls and Documentation*

In this section, the applicant discussed control effectiveness, energy impacts, environmental impacts and economic impacts for the top control technology.

The facility has indicated that Oxidation Catalyst must be installed downstream of the particulate control device to ensure the catalyst is not chemically damaged. However, significant amounts of auxiliary fuel will be required to reheat the flue gas. Preliminary estimates indicate that an additional 73,900 scf/hr of natural gas combustion would be required to provide heating to a minimum catalytic oxidation requirement of 500F. Finally, the facility indicated that the annualized costs for a stand-alone oxidation catalyst system are estimated to be \$21,000 per ton of CO removed (refer to Appendix C of Application No. 20207 – Volume I dated August 10, 2011 for more information on the energy and economic impacts).

Based on the annualized cost, as well as the use of renewable fuel source to achieve the emissions reductions for a predominately renewable energy generation source, the facility has concluded that the use of good design and operation practices is the logical BACT control technology for CO emissions from the biomass boiler. Please refer to pages 6-13 and 6-14 of the facility permit Application No. 20207 – Volume I dated August 10, 2011.

The use of bubbling fluidized bed technology will inherently lower CO emissions due to the fluidized bed combustion process.

*Step 5: Selection of BACT*

According to the facility Application No. 20207, the proposed BACT for the new No. 3 Biomass Boiler includes good design and operation practices. GPI has proposed a BACT limit of 0.15 lb/MMBtu on a 30 day average for CO emissions. The applicant has proposed to use a CO CEMS to demonstrate compliance with this limit. In addition, the facility has proposed a secondary CO BACT limit of 407.3 tons per year to address periods of startup and shutdown of the biomass boiler.

EPD Review – CO Control

In addition to reviewing the permit application and supporting documentation, the Division has performed independent research of the CO BACT analysis and used the following resources and information:

- USEPA RACT/BACT/LEAR/Clearinghouse
- Final Permit and Preliminary Determinations for similar sources, namely We Industries in Rothschild, WI
- Final Permit, Preliminary and Final Determinations, and Permit Application for Warren County Biomass Energy Facility, Georgia and Yellow Pine Energy Company, LLC, Georgia

The Division has prepared a BACT comparison spreadsheet for the similar units using the abovementioned resources and is reflected in Table 4-2. Although oxidation catalyst would provide the highest level of CO emissions reduction, the Division has considered that achieving the relatively moderate emissions reductions to be cost prohibitive.



Most biomass units listed in the RBLC for CO emissions are utility units, which will in theory, have lower emissions due to the steady-state nature of energy generation. At a pulp mill, swings in steam demand and a higher number of shutdowns are likely to occur due to process upsets or other equipment malfunctions. Based on the RBLC research conducted by the Division, a range of 0.075 – 0.78 lb/MMBtu was found for various sized biomass boilers going back 10 years. The most similar unit found – based on industry, size and fuel firing – is located at Simpson Paper in Washington at 595 MMBtu/hr, firing woodwaste and mill sludge. Simpson accepted a 0.35 lb/MMBtu (30 day average) in 2007 and uses an overfire air system as BACT controls. However, this is a 1991 stoker boiler that was modified in 2007; therefore the age and type of boiler are different. The facility has a higher moisture content of fuels and uses reprocessed fuel oil instead of natural gas to reduce CO emissions.

Based on the research performed by the Division and review of the applicant's proposal, the use of good boiler design and operating practices is the BACT control technology for CO emissions and 0.15 lb/MMBtu on a 30-day rolling average is the BACT CO emissions limit, excluding emissions from startup and shutdown. A secondary limit of 407.3 tons per year will address periods of startup and shutdown of the biomass boiler. To ensure compliance with the limit, the facility will be required to install a CO CEMS at the stack outlet.

#### Conclusion – Carbon Monoxide (CO) Control

The BACT selection for the fluidized bed boiler is summarized in Table 4-3:

**Table 4-3: BACT Summary for the No. 3 Biomass Boiler**

<b>Pollutant</b>	<b>Control Technology</b>	<b>Proposed BACT Limit</b>	<b>Averaging Time</b>	<b>Compliance Determination Method</b>
CO	Good design and operating practices	0.15 lb/ MMBtu (excludes startup and shutdown)	30 day rolling	CEMS
CO	Good design and operating practices	407.3 tpy (includes startup, shutdown & malfunction)	12 month rolling total	CEMS

\*This limit includes emissions during startup, shutdown, and malfunctions

## **5.0 TESTING AND MONITORING REQUIREMENTS**

### Testing Requirements:

The facility will be required to conduct initial performance testing for Filterable PM (40 CFR 60 Subpart Db), particulate matter less than 10 micrometers (PM<sub>10</sub>), and PM<sub>2.5</sub> (Avoidance of 40 CFR 52.21), sulfuric acid mist, and hydrogen chloride emissions from the new No. 3 biomass Boiler, as well as mercury content in the mill sludge. Ongoing testing will occur annually for Filterable PM, PM<sub>10</sub>, and PM<sub>2.5</sub>.

In addition, the general provisions of NSPS provides avenues to obtain permission to use alternative testing and monitoring protocols, and in some cases, to waive testing requirements, when justified.

EPD proposes the following monitoring and testing requirements for the new No. 3 Biomass Boiler:

- a. NO<sub>x</sub> CEMS to verify compliance with the NNSR Avoidance emission standards.
- b. CO CEMS to verify compliance with the CO BACT emission standards.
- c. Continuous Opacity Monitor to verify compliance with the opacity standard.
- d. Initial performance tests and annually thereafter (Method 5 in conjunction with Method 202) to verify compliance with the PM<sub>10</sub> PSD Avoidance standards.
- e. Initial performance tests and annually thereafter (Method 5 in conjunction with Method 202) to verify compliance with the filterable PM NSPS Db emission standard.
- f. Initial performance tests and annually thereafter (Method 5 in conjunction with Method 202) to verify compliance with the PM<sub>2.5</sub> NNSR Avoidance emission standards.
- g. Initial performance tests (Method 26 or Method 26A) to establish an emission factor and verify compliance with hydrogen chloride (HCl) emission rate standard.
- h. Initial performance tests (Method 8) to establish emissions factor value for sulfuric acid mist emissions.
- i. CO<sub>2</sub> or O<sub>2</sub> monitors at each location where emissions are monitored to measure the CO<sub>2</sub> or O<sub>2</sub> content of the flue gas to correct pollutant emission concentration.
- j. Instrumentation to continuously measure the sorbent injection rate into a sorbent injection system, if determined to be required.
- k. Instrumentation to measure the steam production rate of the No. 3 Biomass Boiler.
- l. Instrumentation to measure the pressure drop across the No. 3 Biomass Boiler baghouse.

### CAM Applicability:

Because CAM is not applicable and is not being triggered by the proposed modification. Therefore, no CAM provisions are being incorporated into the facility's permit.

## **6.0 AMBIENT AIR QUALITY REVIEW**

An air quality analysis is required to determine the ambient impacts associated with the construction and operation of the proposed modifications. The main purpose of the air quality analysis is to demonstrate that emissions emitted from the proposed modifications, in conjunction with other applicable emissions from existing sources (including secondary emissions from growth associated with the new project), will not cause or contribute to a violation of any applicable National Ambient Air Quality Standard (NAAQS) or PSD increment in a Class I or Class II area. NAAQS exist for NO<sub>2</sub>, CO, PM<sub>2.5</sub>, PM<sub>10</sub>, SO<sub>2</sub>, Ozone (O<sub>3</sub>), and lead. PSD increments exist for SO<sub>2</sub>, NO<sub>2</sub>, and PM<sub>10</sub>.

The proposed project at GPI triggers PSD review for CO. An air quality analysis was conducted to demonstrate the facility's compliance with the NAAQS and PSD Increment standards for CO. An additional analysis was conducted to demonstrate compliance with the Georgia air toxics program. This section of the application discusses the air quality analysis requirements, methodologies, and results. Supporting documentation may be found in the Air Quality Dispersion Report of the application (Volume II date August 10, 2011).

### **Modeling Requirements**

The air quality modeling analysis was conducted in accordance with Appendix W of Title 40 of the Code of Federal Regulations (CFR) §51, *Guideline on Air Quality Models*, and Georgia EPD's *Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions (Revised)*.

The proposed project will cause net emission increases of CO that is greater than the applicable PSD Significant Emission Rates. Therefore, air dispersion modeling analyses are required to demonstrate compliance with the NAAQS and PSD Increment. .

### **Significance Analysis: Ambient Monitoring Requirements and Source Inventories**

Initially, a Significance Analysis is conducted to determine if the CO emissions increases at GPI would significantly impact the area surrounding the facility. Maximum ground-level concentrations are compared to the pollutant-specific U.S. EPA-established Significant Impact Level (SIL). The SIL for the pollutants of concern are summarized in Table 6-1.

If a significant impact (i.e., an ambient impact above the SIL) does not result, no further modeling analyses would be conducted for that pollutant for NAAQS or PSD Increment. If a significant impact does result, further refined modeling would be completed to demonstrate that the proposed project would not cause or contribute to a violation of the NAAQS or consume more than the available Class II Increment.

Under current U.S. EPA policies, the maximum impacts due to the emissions increases from a project are also assessed against monitoring *de minimis* levels to determine whether pre-construction monitoring should be considered. These monitoring *de minimis* levels are also listed in Table 6-1. If either the predicted modeled impact from an emission increase or the existing ambient concentration is less than the monitoring *de minimis* concentration, the permitting agency has the discretionary authority to exempt an applicant from pre-construction ambient monitoring. This evaluation is required for CO emissions.

If any off-site pollutant impacts calculated in the Significance Analysis exceed the SIL, a Significant Impact Area (SIA) would be determined. The SIA encompasses a circle centered on the facility with a radius extending out to (1) the farthest location where the emissions increase of a pollutant from the project causes a significant ambient impact, or (2) a distance of 50 km, whichever is less. All sources within a distance of 50 km of the edge of a SIA are assumed to potentially contribute to ground-level concentrations within the SIA and would be evaluated for possible inclusion in the NAAQS and PSD Increment analyses. EPA promulgated SILs for PM<sub>2.5</sub> on October 20, 2010 (75 FR 64864-64907). EPA has not yet promulgated SILs for the 1-hour NO<sub>2</sub> and 1-hour SO<sub>2</sub> NAAQS).

**Table 6-1: Summary of Modeling Significance Levels**

Pollutant	Averaging Period	PSD Significant Impact Level (ug/m <sup>3</sup> )	PSD Monitoring Deminimis Concentration (ug/m <sup>3</sup> )
CO	8-Hour	500	575
	1-Hour	2000	--

**NAAQS Analysis**

The primary NAAQS are the maximum concentration ceilings, measured in terms of total concentration of pollutant in the atmosphere, which define the “levels of air quality which the U.S. EPA judges are necessary, with an adequate margin of safety, to protect the public health.” Secondary NAAQS define the levels that “protect the public welfare from any known or anticipated adverse effects of a pollutant.” The primary and secondary NAAQS are listed in Table 6-2 below.

**Table 6-2: Summary of National Ambient Air Quality Standards**

Pollutant	Averaging Period	NAAQS	
		Primary / Secondary (ug/m <sup>3</sup> )	Primary / Secondary (ppm)
CO	8-Hour	10,000 / None	9 / None
	1-Hour	40,000 / None	35 / None

If the maximum pollutant impact calculated in the Significance Analysis exceeds the SIL at an off-property receptor, a NAAQS analysis is required. The NAAQS analysis would include the potential emissions from all emission units at GPI, except for units that are generally exempt from permitting requirements and are normally operated only in emergency situations. The emissions modeled for this analysis would reflect the results of the BACT analysis for the modified emission unit. Facility emissions would then be combined with the allowable emissions of sources included in the regional source inventory. The resulting impacts, added to appropriate background concentrations, would be assessed against the applicable NAAQS to demonstrate compliance. For most pollutants with an annual NAAQS, the highest modeled concentration among five consecutive years of meteorological data would be assessed; for pollutants with short-term NAAQS the highest-second high or highest-sixth high would be assessed depending on the pollutant and averaging period.

**PSD Increment Analysis**

The PSD Increments were established to “prevent deterioration” of air quality in certain areas of the country where air quality was better than the NAAQS. To achieve this goal, U.S. EPA established PSD Increments for certain pollutants. The sum of the PSD Increment concentration and a baseline concentration defines a “reduced” ambient standard, either lower than or equal to the NAAQS that must be met in an attainment area. Significant deterioration is said to have occurred if the change in emissions occurring since the baseline date results in an off-property impact greater than the PSD Increment (i.e., the increased emissions “consume” more than the available PSD Increment).

U.S. EPA has established PSD Increments for NO<sub>x</sub>, SO<sub>2</sub>, PM<sub>10</sub>, and PM<sub>2.5</sub>; no increments have been established for CO.

**Modeling Methodology**

Details on the dispersion model, including meteorological data, source data, and receptors can be found in EPD’s PSD Dispersion Modeling and Air Toxics Assessment Review in Appendix C of this Preliminary Determination and in Volume II of Application No. 20207 updated August 10, 2011.

### Modeling Results

The Class II area significant impact analysis was conducted for CO emissions. An ambient air boundary was defined with receptors spaced 100 meters from each other, and a 20x20 kilometer (km) receptor grid was used for the significance modeling, being this grid comprised of 3 different segments. The first one extended approximately 3 km from the fence line with 100-meter spaced receptors in a Cartesian grid. The 2nd segment extended from the edge of the first segment for an additional 3 km with 250-meter spaced receptors. The 3rd segment extended from the edge of the 2nd segment for an additional 6 km with 500-meter spaced receptors. The entire receptor grid for the AERMOD analysis covered a circular area with a radius of 12 km.

Table 6-3 shows that the proposed project will not cause ambient impacts of CO above the appropriate SIL. Because the CO emissions increases from the proposed project result in ambient impacts less than the SIL, no further PSD analyses (i.e., NAAQS and PSD Increment analyses) were conducted for CO emissions.

**Table 6-3: Class II Significance Analysis Results – Comparison to SILs**

Pollutant	Averaging Period	Year	UTM East (m)	UTM North (m)	Maximum Impact (ug/m <sup>3</sup> )	SIL (ug/m <sup>3</sup> )	Significant?
CO	1-hour		253527.60	3629021.50	29.68	2000	No
	8-hour	1990	253528.10	3629041.30	15.33	500	No

Data for worst year provided only.

### Ambient Monitoring Requirements

**Table 6-4: Significance Analysis Results – Comparison to Monitoring *De Minimis* Levels**

Pollutant	Averaging Period	Year*	UTM East (m)	UTM North (m)	Monitoring De Minimis Level (ug/m <sup>3</sup> )	Modeled Maximum Impact (ug/m <sup>3</sup> )	Significant?
CO	8-hour	1990	253528.10	3629041.30	575	15.33	No

\*Data for worst year provided only

The impacts for CO quantified in Table 6-3 of the Class II Significance Analysis are compared to the Monitoring *de minimis* concentrations, shown in Table 6-4, to determine if ambient monitoring requirements need to be considered as part of this permit action. Because all maximum modeled impacts are below the corresponding *de minimis* concentrations, no pre-construction monitoring is required for CO.

### Class I Area Analysis

In addition to evaluating the project's impact on Class II areas, the applicant must also evaluate the project's impact on nearby Class I areas. Although Georgia EPD is the permitting authority for emission sources in Georgia, the Federal Land Manager (FLM) must be consulted separately regarding the potential impact of the proposed major modification on any nearby Class I areas (within 300 km).

Eight Class I areas are located within 300 km of GPI in Macon. The magnitude of the emissions from the proposed major modification do not warrant a review of impacts per the Federal Land Manager.

On February 28, 2011, the facility notified the National Park Service (NPS), the United States Fish and Wildlife (FWS), and the USDA Forest Service (FS) regarding all applicable Class I areas within 300 km of the facility.

**Table 6-5: Class I Area Analysis**

Class I areas within 300 km and responsible FLM	Distance (km)	Sum of Visibility-Affecting Pollutant Emissions – Project (tpy)	FLAG 2010 Approach Q/D	Sum of Visibility-Affecting Pollutant Emissions – Net Emissions (tpy)	FLAG 2010 Approach Q/D
Cohutta (GA) – FS	246	1419.9	5.8	59.6	0.2
Okefenokee (GA) - FWS	227		6.3		0.3
Joyce Kilmer/Slickrock (NC/TN) - FS	288		4.9		0.2
Great Smoky Mountains (NC/TN) – NPS	294		4.8		0.2
Shinig Rock (NC) – FS	293		4.8		0.2
Saint Marks (FL) – FWS	293		4.8		0.2
Bradwell Bay (FL) – FS	295		4.8		0.2
Wolf Island (GA) – FWS	267		5.3		0.2

All Q/D values were well below ten, which suggest the project will have no adverse impacts to any AQRVs. No responses were made by any of the three Federal Land Manager services.

## **7.0 ADDITIONAL IMPACT ANALYSES**

PSD requires an analysis of impairment to visibility, soils, and vegetation that will occur as a result of a modification to the facility and an analysis of the air quality impact projected for the area as a result of the general commercial, residential, and other growth associated with the proposed project.

### Soils and Vegetation Analysis

The U.S. EPA has developed certain screening concentrations below which it can be reasonably assumed that the soils and vegetation in the vicinity of a proposed project will not experience any adverse effects due to air emissions associated with the project. These threshold concentrations are listed in Table V of the Model Request Form that is attached to the EPD's PSD Dispersion Modeling and Air Toxics Assessment Review in Appendix C, and were compiled from EPA's Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals (EPA, 1980). Table V presents a comparison of the proposed facility's worst-case impacts to these screening concentrations. Review of that table indicates the highest predicted impacts are all well below the screening concentrations.

### Growth Analysis (Demographics)

The growth analysis is a projection of the commercial, industrial, residential, and other growth that may be projected to occur in the area as a result of the construction and operation of the proposed source. The anticipated increase in industrial, commercial, or residential growth in the area as a direct result of the proposed project will be negligible. Long-term, it is not anticipated that a significant number of new jobs will be generated by this project. No significant amount of related industrial growth is expected to accompany the operation of the plant. Since no significant associated commercial or industrial growth is projected as a result of the proposed action, negligible growth-related air pollution impacts are expected.

### Class I Visibility Analysis

Visibility impairment is any perceptible change in visibility (visual range, contrast, atmospheric color, etc.) from that which would have existed under natural conditions. Poor visibility is caused when fine solid or liquid particles, usually in the form of volatile organics, nitrogen oxides, or sulfur oxides, absorb or scatter light. This light scattering or absorption actually reduces the amount of light received from viewed objects and scatters ambient light in the line of sight. This scattered ambient light appears as haze.

Another form of visibility impairment in the form of plume blight occurs when particles and light-absorbing gases are confined to a single elevated haze layer or coherent plume. Plume blight, a white, gray, or brown plume clearly visible against a background sky or other dark object, usually can be traced to a single source such as a smoke stack.

Georgia's SIP and Georgia *Rules for Air Quality Control* provide no specific prohibitions against visibility impairment other than regulations limiting source opacity and protecting visibility at federally protected Class I areas. To otherwise demonstrate that visibility impairment will not result from continued operation of the mill, the VISCREEN model was used to assess potential impacts on ambient visibility at so-called "sensitive receptors" within the SIA of the GPI. Since there is no ambient visibility protection standard for Class II areas, this analysis is presented for informational purposes only and predicted impacts in excess of screening criteria are not considered "adverse impacts" nor cause further refined analyses to be conducted.

There is no ambient visibility protection standard for a Class II area. For this reason, it was not necessary to conduct an analysis of Class II visible plume impacts.

### Georgia Toxic Air Pollutant Modeling Analysis

Georgia EPD regulates the emissions of toxic air pollutant (TAP) emissions through a program covered by the provisions of *Georgia Rules for Air Quality Control*, 391-3-1-.02(2)(a)3.(ii). A TAP is defined as any substance that may have an adverse effect on public health, excluding any specific substance that is covered by a State or Federal ambient air quality standard. Procedures governing the Georgia EPD's review of TAP emissions as part of air permit reviews are contained in the agency's "*Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions (Revised)*."

#### Selection of Toxic Air Pollutants for Modeling

For projects with quantifiable increases in TAP emissions, an air dispersion modeling analysis is generally performed to demonstrate that off-property impacts are less than the established Acceptable Ambient Concentration (AAC) values. The TAP evaluated are restricted to those that may increase due to the proposed project. Thus, the TAP analysis would generally be an assessment of off-property impacts due to facility-wide emissions of any TAP emitted by a facility. To conduct a facility-wide TAP impact evaluation for any pollutant that could conceivably be emitted by the facility is impractical. A literature review would suggest that at least one molecule of hundreds of organic and inorganic chemical compounds could be emitted from the various combustion units. This is understandable given the nature of the biomass and natural gas fed to the combustion sources, and the fact that there are complex chemical reactions and combustion of fuel taking place in some. The vast majority of compounds potentially emitted however are emitted in only trace amounts that are not reasonably quantifiable.

GPI evaluated all compounds that could possibly be emitted from the proposed boiler, and then narrowed the list based on current emission standards, such as 40 CFR 63 Subparts MM, S, and DDDDD. EPD further used emission rates as given in AP-42 Table 1.6-3 (Emission Factors For Speciated Organic Compounds, TOC, VOC, NO<sub>x</sub>, and CO from Wood Residue Combustion) to evaluate which TAP should be included in the analysis.

For each TAP identified for further analysis, both the short-term and long-term acceptable ambient concentrations (AACs) were calculated following the procedures given in Georgia EPD's *Guideline*. Figure 8-3 of Georgia EPD's *Guideline* contains a flow chart of the process for determining long-term and short-term ambient thresholds. GPI referenced the resources previously detailed to determine the long-term (i.e., annual average) and short-term AAC (i.e., 24-hour or 15-minute). The AACs were verified by the EPD.

**Table 7-1: Air Toxics Results – Modeled Maximum Ground Level Concentration (MGLC) and the Respective AAC**

TAP	Long-term averaging period	MGLC (ug/m <sup>3</sup> )	LT AAC (ug/m <sup>3</sup> )	Short-term averaging period	MGLC (ug/m <sup>3</sup> )	ST AAC (ug/m <sup>3</sup> )
Acetaldehyde	Annual	2.90E+00	4.55E+00	15-min	3.27E+02	4.50E+03
Acrolein	Annual	5.36E-02	1.5E-01	15-min	6.18E+00	2.30E+01
Arsenic	Annual	6.00E-05	2.33E-04	15-min	8.42E-03	2.00E-01
Cadmium	Annual	3.00E-05	5.56E-03	15-min	2.07E-03	3.00E+01
Carbon Tetrachloride	Annual	7.21E-02	1.7E+00	15-min	2.30E+01	1.57E+04
Formaldehyde	Annual	2.29E-01	7.7E-01	15-min	2.51E+01	2.43E+02
Lead*	N/A			N/A		
Manganese	Annual	2.86E-03	5.00E-02	15-min	4.89E-01	5.00E+02
Mercury	Annual	2.00E-05	3.00E-01	15-min	2.76E-03	1.0E+01

\*Lead compliance is reported in Table 7-2

The annual and 15-minute AAC of the above toxic air pollutants were reviewed based on U.S EPA IRIS reference concentration (RfC) and OSHA Permissible Exposure (PEL). Note that the annual Acrolein AAC of 0.15 ug/m<sup>3</sup> was obtained from the final Development Support Documents (DSDs) on the Texas Commission on Environmental Quality (TCEQ) website, and approved by the Georgia State Environmental Toxicology Coordinator. Table 7-1 summarized the AAC levels and the MGLC of the TAP at the averaging periods. To obtain 15-minute average impacts, model output of the 1-hour average concentrations was multiplied by the conversion factor of 1.32. As shown in the table, all modeled TAP are well below their respective AAC levels. Therefore, all air toxics evaluated by the applicant meet the applicable Georgia Air Toxics Guideline Acceptable Ambient Concentrations. The ISCT3 model was conservatively used in the review of the air toxics concentrations.

Lead was requested to be modeled as a toxic air pollutant; however, EPD determined that comparing the level to the NAAQS was more conservative. Please note that the project did not trigger PSD review for lead (0.1 tpy project emissions versus the 0.6 tpy PSD threshold).

**Table 7-2: Projected Impact – NAAQS for Lead**

Pollutant	Averaging Period	UTM East (m)	UTM North (m)	All Source Impact (ug/m <sup>3</sup> )	Total Impact (ug/m <sup>3</sup> )	NAAQS (ug/m <sup>3</sup> )
Pb	3-month	254389.4	3628745.8	0.004	0.044	0.15

\*Highest concentration of 3-month trolling average over the 5 modeling years

### **Determination of Toxic Air Pollutant Impact**

The Georgia EPD *Guideline* recommends a tiered approach to model TAP impacts, beginning with screening analyses using SCREEN3, followed by refined modeling, if necessary, with ISCST3 or ISCLT3. For the refined modeling completed, the infrastructure setup for the SIA analyses was relied upon with appropriate sources added for the TAP modeling. Note that per the Georgia EPD's *Guideline*, downwash was not considered in the TAP assessment.

### **Initial Screening Analysis Technique**

Generally, an initial screening analysis is performed in which the total TAP emission rate is modeled from the stack with the lowest effective release height to obtain the maximum ground level concentration (MGLC). Note the MGLC could occur within the facility boundary for this evaluation method. The individual MGLC is obtained and compared to the smallest AAC. Due to the likelihood that this screening would result in the need for further analysis for most TAP, the analyses were initiated with the secondary screening technique.

Screening modeling was not performed in this case due to a larger number of sources and toxics being evaluated; therefore, refined modeling was carried out. The U.S. EPA ISCT3 model (02035) was used to assess emissions from the non-emergency and significant units at GPI, as allowed per Georgia guidelines. As this refined model showed no impacts above the AAC, no further modeling or evaluation was necessary.

## **8.0 EXPLANATION OF DRAFT PERMIT CONDITIONS**

The permit requirements for this proposed facility are included in draft Permit Amendment No. 2631-021-0001-V-03-2.

### **Section 1.0: Facility Description**

The facility is installing a new bubbling fluidized bed boiler No. 3 Biomass Boiler (Source Code: B005) rated at approximately 620 MMBtu/hr to be equipped with flue gas recirculation, a baghouse, and a selective non-catalytic (SNCR) reduction system and hazardous air pollutant control (some type of sorbent injection). No. 3 Biomass Boiler will combust biomass, natural gas, and mill wastewater treatment plant (WWTP) sludge. The facility will also shutdown existing No. 1 Power Boiler (Source Code: B001) which combusts coal, fuel oil, and natural gas. Coal and fuel oil will no longer be used as fuel in the No. 2 Power Boiler (Source Code: B002) with natural gas combustion capability being retained.

### **Section 2.0: Requirements Pertaining to the Entire Facility**

No conditions in Section 2.0 are being added, deleted or modified as part of this permit action.

### **Section 3.0: Requirements for Emission Units**

New Permit Condition 3.2.1 limits the facility to 219,000 MW-hours per 12 month period of electric output for sale in order to avoid the requirements of 40 CFR 72.6 (Acid Rain Program).

Modified Permit Conditions 3.3.23 and 3.3.28 and new Permit Conditions 3.3.30 and 3.3.31 are general rule applicability requirements for the No. 3 Biomass Boiler.

New Permit Condition 3.3.32 defines the fuels that may be fired in the No. 3 Biomass Boiler. GPI has no intention of firing any fuel that could be defined as “solid waste” under 40 CFR 241. It includes the definition of clean cellulosic biomass from 40 CFR 241.2.

New Permit Condition 3.3.33 outlines all applicable emission limitations for the No. 3 Biomass Boiler. The facility avoided PSD review by taking limits for sulfuric acid mist (SAM), PM<sub>10</sub>, PM<sub>2.5</sub>, and NO<sub>x</sub>. The facility avoided a 112(g) case-by-case MACT by taking limit for hydrogen chloride (HCl) and total HAP. The facility took the listed 40 CFR 60 Subpart Db limit for filterable PM and opacity, the listed 40 CFR 61 Subpart E limit for mercury content in the mill sludge, and BACT limits for CO emissions.

- a. Nitrogen oxides (NO<sub>x</sub>) in excess of 404.6 tons during any consecutive 12-month period. This limit applies during all times of operation, including startup, shutdown, and malfunction.
- b. Sulfuric acid mist (SAM) in excess of 13.2 tons during any consecutive 12-month period. This limit applies during all times of operation, including startup, shutdown, and malfunction.
- c. Filterable particulate matter (PM) in excess of 0.030 lb/MMBtu. This limit applies during all times of operation, except during periods of startup, shutdown, and malfunction.
- d. PM<sub>2.5</sub> in excess of 0.040 lb/MMBtu. This limit applies during all times of operation, except during periods of startup, shutdown, and malfunction.
- e. Particulate matter less than 10 micrometers in diameter (PM<sub>10</sub>) in excess of 0.049 lb/MMBtu. This limit applies during all times of operation, except during periods of startup, shutdown, and malfunction.

- f. Opacity of which is equal to or greater than 20% opacity (six-minute average), except for one six-minute period per hour of not more than 27% opacity. This opacity standard applies during all times of operation, except during periods of startup, shutdown, and malfunction.
- g. Carbon monoxide (CO) in excess of 0.15 lb/MMBtu on a 30-day rolling average, excluding periods of startup, shutdown, and malfunction.
- h. CO in excess of 407.3 tons during any consecutive 12-month period. This limit applies during all times of operation, including startup, shutdown, and malfunction.
- i. Hydrogen Chloride (HCl) emissions in excess of 9.9 tons during consecutive 12-month period. This limit applies during all times of operation, including startup, shutdown, and malfunction.
- j. Any single hazardous air pollutant (HAP) which is listed in Section 112 of the Clean Air Act in an amount equal to or exceeding 10 tons during any consecutive twelve months, or any combination of such listed pollutants in an amount equal to or exceeding 25 tons during any twelve consecutive months.
- k. Mercury in excess of 7.1 pounds per 24-hour period while burning mill sludge.

New Permit Condition 3.3.34 limits the facility to 10% annual capacity factor for fossil fuels on the No. 3 Biomass Boiler. This restriction allowed the facility to avoid a NO<sub>x</sub> emission limitation under 40 CFR 60 Subpart Db.

New Permit Condition 3.3.35 limits the natural gas firing rate to 249 MMBtu/hr in the No. 3 Biomass Boiler. This restriction allows the facility to avoid applicability to 40 CFR 60 Subpart Da.

New Permit Condition 3.3.36 limits the fuel-firing scenarios by restricting the burning of natural gas with mill sludge so as to keep the potential SO<sub>2</sub> emission rate at less than 0.32 lb/MMBtu, thus avoiding the SO<sub>2</sub> emission limits under 40 CFR 60 Subpart Db.

New Permit Condition 3.4.14 limits the sulfur content of the fuel fired in the No. 3 Biomass Boiler to 3%, by weight, or less.

New Permit Conditions 3.4.15 and 3.4.16 limits the opacity and PM emissions from the Bark Hog Tower and Hammer Hog to the limits allowed by Georgia Rules (b) and (e).

#### Section 4.0: Requirements for Testing

Permit Condition 4.1.3 was modified to include new applicable test methods for the No. 3 Biomass Boiler. Some existing test methods are also applicable.

Permit Conditions 4.2.1 and 4.2.2 were modified to add yearly testing for Filterable PM, PM<sub>10</sub> and PM<sub>2.5</sub>.

New Permit Condition 4.2.7 requires the facility to conduct a sludge test on the mill sludge to be fired in the No. 3 Biomass Boiler as required by 40 CFR 61 Subpart E.

New Permit Condition 4.2.8 requires the facility to conduct an initial performance test for Filterable PM in order to verify compliance with the 40 CFR 60 Subpart Db PM emission limit. This test will be repeated yearly as dictated by Permit Conditions 4.2.1 and 4.2.2.

New Permit Condition 4.2.9 requires the facility to conduct an initial performance test for total PM<sub>10</sub> and PM<sub>2.5</sub> in order to verify compliance with the PSD Avoidance emission limits and to establish monitoring parameters for the baghouse. This test will be repeated yearly as dictated by Permit Conditions 4.2.1 and 4.2.2.

New Permit Condition 4.2.10 requires the facility to conduct an initial performance test for SAM and HCl emissions to create site-specific emission factors to verify on-going compliance with these limits. If, during testing, the facility determines that a sorbent injection system is needed to maintain compliance, the facility will also establish a feed rate of sorbent to be monitored.

New Permit Condition 4.2.11 requires the facility to conduct a performance evaluation of the CO CEMS that will be installed on the No. 3 Biomass Boiler in order to establish the first 30-day rolling average.

New Permit Condition 4.2.12 requires the facility to conduct performance evaluations on the NO<sub>x</sub> CEMS and COMS.

#### Section 5.0: Requirements for Monitoring

Modified Permit Condition 5.2.1 requires the facility to install CO, NO<sub>x</sub>, and diluent (O<sub>2</sub>) CEMS and COMS on the No. 3 Biomass Boiler.

Modified Permit Condition 5.2.2 requires the facility to continuously monitor pressure drop across the new baghouse and steam production rate of the No. 3 Biomass Boiler.

Modified Condition 5.2.3 requires the facility to monitor fuel types and amounts and heat input from natural gas on the No. 3 Biomass Boiler. If, during compliance testing, the facility determines the need for sorbent injection, they will also monitor feed rate of sorbent.

New Permit Condition 5.2.9 requires the facility to develop a Preventative Maintenance Program for the new baghouse.

New Permit condition 5.2.10 requires the facility to conduct weekly (or otherwise, as determined by the Division) fuel analysis in order to determine compliance with the 0.32 lb/MMBtu emission exemption under 40 CFR 60 Subpart Db.

#### Section 6.0: Other Recordkeeping and Reporting Requirements

Permit condition 6.1.7 was modified to include excess emissions, exceedances, excursions, and other reportables from the No. 3 Biomass Boiler.

New permit Condition 6.2.28 was added to require the facility to calculate all electricity sold to the grid in order to prove compliance with the Acid Rain avoidance condition.

New Permit Condition 6.2.29 allows the facility to have a 180-day shakedown period for the No. 3 Biomass Boiler under 40 CFR 52.21.

New Permit Condition 6.2.30 requires the facility to develop a site-specific fuel analysis plan as allowed by 40 CFR 60 Subpart Db in order to avoid SO<sub>2</sub> emission limits.

New Permit Condition 6.2.31 outlines the notifications required during the construction of No. 3 Biomass Boiler and the removal of No. 1 Power Boiler.

New Permit Condition 6.2.32 requires the facility to calculate the annual capacity factor for the No.3 Biomass Boiler while firing natural gas.

New Permit Condition 6.2.33 requires the facility to monitor mercury emissions yearly from the mill sludge if the initial sludge test shows emissions above 3.5 lb/24 hours.

New Permit Condition 6.2.34 requires the facility to maintain annual certifications from the supplies that all fuel meets the biomass definition contained in Condition 3.3.32.

New Permit Conditions 6.2.35 and 6.2.36 outline the methods by which the facility will calculate monthly and 12-month rolling total NO<sub>x</sub> emissions, and notifications to the Division should emissions exceed the 33.7 tons per month.

New Permit Conditions 6.2.37 and 6.2.38 outline the methods by which the facility will calculate monthly and 12-month rolling total CO emissions, and notifications to the Division should emissions exceed the 33.9 tons per month or 407.3 tons per year.

New Permit Conditions 6.2.39, 6.2.40, and 6.2.41 outline the methods by which the facility will calculate monthly and 12-month rolling total SAM emissions, and notifications to the Division should emissions exceed the 1.1 tons per month or 13.2 tons per year.

New Permit Conditions 6.2.42, 6.2.43, and 6.2.44 outline the methods by which the facility will calculate monthly and 12-month rolling total HCl emissions, and notifications to the Division should emissions exceed the 0.825 tons per month or 9.9 tons per year.

New Permit Conditions 6.2.45, 6.2.46, and 6.2.47 outline the methods by which the facility will calculate monthly and 12-month rolling total of individual (excluding HCl) and total HAP (including HCl) emissions, and notifications to the Division should emissions exceed the 2.08 tons per month or 25 tons per year for total HAP, or exceed 0.833 tons per month or 10 tons per year for individual HAP (excluding HCl).

#### Section 7.0: Other Specific Requirements

New Permit Condition 7.14.1 states that when the facility removes the coal and fuel oil firing capabilities from the Nos. 1 and 2 Power Boilers and they are only capable of firing natural gas, the facility will no longer be required to conduct yearly testing for PM, no longer be required to monitor the power boilers scrubbers, and no longer be required to record fuel types fired in these boilers.

New Permit Condition 7.14.2 states that all applicable requirements of the No. 3 Biomass Boiler will become effective upon startup and notification to the Division regarding startup of the unit.

New Permit Condition 7.14.3 states that once the No. 1 Power Boiler is shutdown, all applicable requirements for this unit become null and void.

New permit Condition 7.14.4 states that if the facility determines that a sorbent injection system is not needed to maintain compliance with the applicable emission limits, the facility does not have to comply with the sorbent system related conditions.

## APPENDIX A

Draft Title V Construction Permit Amendment  
Graphic Packaging international, Inc.  
Macon (Bibb County), Georgia

## APPENDIX B

### Graphic Packaging international, Inc. PSD Permit Application and Supporting Data

#### Contents Include:

1. PSD Permit Application No. 20207, Volume I - dated January 28, 2011 (updated April 19, 2011)
2. Consolidated PSD Permit Application No. 20207 for Volume I, completely updated August 10, 2011
3. Consolidated PSD Permit Application No. 20207, Volume II – Modeling - dated February 28, 2011 (updated April 19 and August 10, 2011)

## APPENDIX C

### EPD'S PSD Dispersion Modeling and Air Toxics Assessment Review