GEORGIA
DEPARTMENT OF NATURAL RESOURCES
ENVIRONMENTAL PROTECTION DIVISION

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NARRATIVE

TO: Wendy Troemel

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DATE: April 23, 2025

Facility Name:	**Altamaha Green Energy, LLC**
AIRS No.:	30500039
Location:	Jesup, GA (Wayne County)
Application No.:	29489
Date of Application:	October 31, 2024

Background Information

The new facility is Altamaha Green Energy, LLC (AGE) which will be located in Jesup, Wayne County. It is a joint venture between Rayonier Performance Fibers, LLC (RPF) and Beasley Green Power, LLC (BGP). Upon construction and startup of operations, the facility will be a major source with regard to the Title V regulations. The facility is a 1,037 million British thermal units per hour (MMBtu/hr) circulating fluidized bed (CFB) biomass cogeneration boiler (CFB Boiler) to produce heat energy and electricity for the power grid. The CFB Boiler will also be fired with natural gas. The natural gas will be used only for startups and as a back-up fuel. When firing natural gas, the CFB Boiler will have a heat input capacity of 359 MMBtu/hr. Total annual consumption of natural gas will be limited to less than 10 percent of total annual boiler heat input while combusting biomass. The CFB Boiler's new auxiliary equipment will include a biomass storage pile, a sorbent silo, a bottom ash handling system, a fly ash silo, a cooling tower, a diesel fire pump engine, a diesel emergency engine, paved and unpaved roadways, a sand silo, a bark hog system, and a truck tipper. The CFB Boiler and its auxiliary equipment will be constructed on the property of RPF, a Kraft pulp mill located in Jesup, Georgia.

Once the CFB Boiler shakedown period is completed, it will supply steam to the RPF Plant displacing the steam supplied by RPF's No. 3 Power Boiler (Source Code: PB03). RPF will permanently shut down PB03 at the completion of the shakedown period of the CFB Boiler. Therefore, concurrent with this State Implementation Plan (SIP) application for AGE, RPF is submitting a separate Title V Significant Modification permit application to remove PB03 and its associated conditions and applicable requirements from the RPF's Title V Operating Permit (TVOP). Based on the regulatory definition of stationary source and a review of associated U.S. EPA guidance, both AGE and RPF Plant are considered a single major stationary source under both Federal and State major New Source Review (NSR) air permitting rules and the TVOP program for the following reasons:

- The new CFB will be contiguous with the existing RPF plant because it will be located on the property of the RPF Kraft pulp plant via a long-term lease from RPF.

- The new CFB will be under common control with the RPF plant because RPF is part-owner of the AGE joint venture that will construct and own the CFB, and RPF will have day-to-day control over activities at the CFB that will affect the applicability of and compliance with environmental requirements by providing operating and maintenance services to AGE using RPF's existing employees.

- The CFB and the RPF may be considered part of the same industrial grouping (even though the first two digits of their SIC codes are different) because of the dependency of each facility on the other, resulting in support facility relationships. Specifically, RPF will be responsible for arranging for delivery of 50% of the biomass necessary to operate the boiler, the CFB will provide the supplemental steam that RPF will need for its operations following the shutdown of PB03, RPF will return condensate or excess medium pressure steam to the CFB to operate a steam turbine that AGE will use to generate electricity for sale, and RPF will provide site services to the AGE project including utilities and site maintenance services.

For the foregoing reasons, the proposed project (Project) can be considered as a modification of the existing RPF permit. However, for administrative purposes, AGE and RPF have requested to maintain separate Title V operating permits for the existing pulp mill and the new CFB and its associated auxiliary equipment.

Therefore, the Project will include installing CFB and permanently shutting down PB03 at the RPF mill and AGE will be responsible for all permitting and compliance requirements associated with the new facility.

<u>Purpose of Application</u>

The purpose of the application is to obtain a permit to construct and operate a CFB Boiler and its associated equipment at Jesup, Georgia. The application was received on October 31, 2024, and assigned number 29489. A public advisory was issued and expired on December 11, 2024. This permit was written taking into consideration comments received during the public advisory period.

Equipment List

Emission Units			Associated Control Devices	
Source Code	**Description**	**Installation Date**	**Source Code**	**Description**
SP	Biomass Storage Pile	2025	N/A	N/A
SS	Sorbent Silo	2025	VF-2	Bin Vent
AS	Flyash Silo	2025	VF-1	Bin Vent
AH	Bottom Ash Handling	2025	N/A	N/A
CT	Cooling Tower	2025	N/A	N/A
EE	Diesel Emergency Engine	2025	N/A	N/A
FPE	Diesel Fire Pump Engine	2025	N/A	N/A
---	Plant Roads	2025	N/A	N/A
---	Sand Silo	2025	N/A	N/A
---	Bark Hog System	2025	N/A	N/A
---	Truck Tipper	2025	N/A	N/A

Fuel Burning Equipment

Source Code	Input Heat Capacity (MMBtu/hr)	Description	Installation Date	Construction Date
B01	1,037	Circulating Fluidized Bed (CFB) Boiler	2025	2025

Emissions Summary

Circulating Fluidized Bed Biomass Cogeneration Boiler (Source Code: B01)

The circulating fluidized bed (CFB) biomass cogeneration boiler has a maximum heat input capacity of 1,037 million British thermal units per hour (MMBtu/hr) when burning biomass. The boiler will be capable of burning natural gas during periods of startups and shutdowns and as back-up fuel. When burning natural gas, the boiler has a maximum heat input capacity of 359 MMBtu/hr. Total annual consumption of natural gas is limited to less than 10 percent of total annual boiler heat input (908,412 MMBtu). The CFB boiler is considered an electric utility steam generating unit because it will supply more than one-third of its potential electric output to the power distribution system for sale.

The CFB boiler's auxiliary equipment includes a biomass storage pile, a sorbent silo, a bottom ash handling system, a fly ash silo, a cooling tower, a diesel fire pump engine, a diesel emergency engine, paved and unpaved roadways, a sand silo, a bark hog system, and a truck tipper.

The CFB boiler will supply steam to the RPF Plant and replace the steam supplied by RPF's No. 3 Power Boiler (PB03). RPF will permanently shut down PB03 not later than 60 days after the completion of the shakedown period of the CFB Boiler. Therefore, concurrent with this State Implementation Plan (SIP) application for the AGE Facility, RPF has submitted a separate Title V Significant Modification permit application to remove PB03 and its associated conditions and applicable requirements from the RPF Plant's Title V Operating Permit No. 2611-305-0001-V-05-0, and Permit Amendment Nos. 2611-305-0001-V-05-1, 2611-305-0001-V-05-2, and 2611-305-0001-V-05-3.

As indicated, both the AGE Facility and RPF Plant are considered a single major stationary source under both Federal and State major New Source Review (NSR) air permitting rules and the TVOP program. The CFB Boiler will operate with a baghouse (BH-1) for particulate matter (PM) control, selective non-catalytic reduction (SNCR-1) for nitrogen oxides (NOx) control, and sorbent injection (SI-1) for hydrogen chloride (HCl) and sulfur dioxide (SO_2) control. Vent filters (VF-1 and VF-2) will control PM emissions from the Sorbent silo and Fly Ash silo. Carbon monoxide (CO), Volatile organic compounds (VOC), and other related contaminants will be minimized through the CFB Boiler design and good operating practices. The CFB Boiler will have no impact on the operations or the other existing units at RPF other than to provide the steam previously provided by PB03. Neither steam demand for operation of the RPF Plant nor pulp production will be affected by the AGE Project.

PSD Applicability Evaluation

Considered alone, the AGE facility emissions increase triggers the Prevention of Significant Deterioration of Air Quality (PSD) rules. However, PB03 will be shut down and emissions from both AGE and PB03 must be considered to determine whether the net emission increase for any regulated pollutant is significant to trigger PSD permitting. To accomplish this evaluation, the hybrid test is used. Pursuant to 40 CFR 52.21(a)(2)(iv)(f), the PSD applicability analysis is based on the hybrid test because the Project includes both new emissions units and an existing emissions unit. The hybrid test uses both the "actual-to-projected actual" approach and the "actual-to-potential" approach to calculate the total Project emissions increase. For new emissions units, the increases are based on potential to emit (PTE) emissions. For the existing unit, the project increases are the difference between the projected actual emissions (PAE) and baseline actual emissions (BAE). The existing emissions unit for the Project is PB03, and since this unit is being permanently shut down, the PAE rates are zero.

Pursuant to 40 CFR 52.21(b)(48)(ii), BAE is the average rate, in tons per year (ton/yr), at which the emissions unit actually emitted each regulated pollutant during any consecutive 24-month period selected by the owner or operator within the 10-year period immediately preceding either the date the owner or operator begins actual construction of the Project, or the date a complete permit application is received by the Georgia Environmental Protection Division (GEPD). BAE are based on historic emissions reported to GEPD as part of annual Emissions Inventory System (EIS) reporting requirements. BAE for PB03 were evaluated for the following regulated NSR pollutants: PM (filterable), PM_{10} (filterable + condensable), $PM_{2.5}$ (filterable + condensable), SO_2, CO, VOC, Pb, and NOx.

Pursuant to 40 CFR 52.21(b)(41)(i), PAE is the maximum annual rate, in ton/yr, at which an existing emissions unit is projected to emit a regulated NSR pollutant in any one of the five years following the date the unit resumes regular operation after the Project. Since PB03 will be permanently shut down following completion of the shakedown of AGE's CFB Boiler, PAE for all pollutants from PB03 will be zero ton/yr.

Pursuant to 40 CFR 52.21(b)(4), PTE is the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. For the PTE calculations, the CFB Boiler's potential fuel throughputs were based on the boiler's design capacity of 1,037 MMBtu/hr of biomass and 365 days of operation. Total annual consumption of natural gas was limited to less than 10 percent of total annual boiler heat input. PTE emissions rates were based on the worst-case fuel mix (i.e., maximum emissions rate) for each pollutant. The CFB Boiler emissions factors were based on a combination of stack testing, vendor guarantees, and AP-42 emissions factors. Emissions factors and capacities for the auxiliary equipment were also based on vendor guarantees. The paved and unpaved roadways emissions factors were based on AP-42 Section 13 and site-specific data based on trucks carrying purchased chips and bark. The CFB Boiler's auxiliary equipment is expected to emit PM, PM_{10}, and $PM_{2.5}$ only because they are all material handling sources or cooling towers.

The Environmental Protection Agency (EPA) proposed a revision (EPA Docket ID: EPA-HQ-OAR-2018-0048) to certain New Source Review (NSR) applicability regulations to clarify the requirements that apply to sources proposing to undertake a physical or operational change (i.e., a project) under the NSR preconstruction permitting program and finalized these changes on November 24, 2020. Under this program, an existing major source proposing to undertake a project must determine whether that project will constitute a major modification following a two-step applicability test and thus be subject to the NSR preconstruction permitting requirements. The first step is to determine if the proposed project will cause a 'significant emissions increase' of a regulated NSR pollutant (Step 1). If the proposed project is projected to cause such an increase, the second step is to determine if there is a 'significant net emissions increase' of that pollutant (Step 2). In this action, the EPA proposed a revision to the NSR applicability regulations to make it clear that both emission increases and emission decreases that result from a given proposed project are to be considered at Step 1 of the NSR major modification applicability test.

A determination of PSD applicability was completed based on the total project-related emission increases from the modified and new emissions units. The total project-related emission increases are calculated as follows:

Project Increases = PTE (new units) + PAE (existing units) – BAE (existing units).

Since PB03 is being permanently shut down, PAE is zero, and

Project Increases = PTE (new units) – BAE (existing units).

Table A-1 of the application (below) shows how the PTE for the CFB boiler was calculated. There are two scenarios: Scenario 1 assumes that 10% of the CFB Boiler's total annual heat input comes from natural gas combustion and 90% of the CFB Boiler's total annual heat input comes from biomass combustion. Scenario 2 assumes the maximum biomass firing rate and a conservative number of natural gas startups (3 total). The worst-case emission scenario was chosen as the PTE for the CFB boiler.

Table A-2 of the application (below) shows how the PTE for the Biomass Storage Pile, the Sorbent Silo, the Fly Ash Silo, the Bottom Ash Handling, the Cooling Tower, the Roadways, the Emergency Engines, the sand silo, the bark hog system, and the truck tipper were calculated.

Tables A-3 through A-5 (below) show:

- The PTE of the New CFB Boiler Project
- The Actual Emission Rates of the No. 3 Power Boiler (PB03)
- Total Project Emissions Increases (PTE – BAE)

Table A-1
Summary of PTE Emissions for CFB Boiler
New Biomass Boiler Project
(tons/year)

Source Description	Throughput	Pollutant	Emissions Factor	Units	Emissions Factor Source	Throughput (Scenario 1)	Throughput (Scenario 2)	Units	PTE (Scenario 1)[d] (tpy)	PTE (Scenario 2)[d] (tpy)
CFB Boiler[a]	Natural Gas[b]	PM	1.86E-03	lb/MMBtu	AP-42 Table 1.4-2	908,412	25,848	MMBtu	0.85	2.41E-02
		PM_{10}	7.45E-03	lb/MMBtu	Filterable portion conservatively assumed to be equal to PM. Includes condensable PM.	908,412	25,848	MMBtu	3.38	9.63E-02
		$PM_{2.5}$	7.45E-03	lb/MMBtu	Filterable portion conservatively assumed to be equal to PM. Includes condensable PM.	908,412	25,848	MMBtu	3.38	9.63E-02
		NO_X	0.10	lb/MMBtu	Vendor guarantee.	908,412	25,848	MMBtu	45.42	1.29
		SO_2	5.88E-04	lb/MMBtu	AP-42 Table 1.4-2	908,412	25,848	MMBtu	0.27	7.60E-03
		CO	0.12	lb/MMBtu	Vendor guarantee.	908,412	25,848	MMBtu	54.50	1.55
		VOC	5.39E-03	lb/MMBtu	AP-42 Table 1.4-2	908,412	25,848	MMBtu	2.45	6.97E-02
		Pb	4.90E-07	lb/MMBtu	AP-42 Table 1.4-2	908,412	25,848	MMBtu	2.23E-04	6.34E-06
	Biomass[c]	PM	4.10E-03	lb/MMBtu	Boiler MACT PM Limit	8,175,708	9,084,120	MMBtu	16.76	18.62
		PM_{10}	2.68E-02	lb/MMBtu	Vendor guarantee plus safety factor. Filterable and condensable PM.	8,175,708	9,084,120	MMBtu	109.55	121.73
		$PM_{2.5}$	2.45E-02	lb/MMBtu	Vendor guarantee. Filterable and condensable PM.	8,175,708	9,084,120	MMBtu	100.15	111.28
		NO_X	8.59E-02	lb/MMBtu	Vendor guarantee plus safety factor	8,175,708	9,084,120	MMBtu	351.15	390.16
		SO_2	1.20E-02	lb/MMBtu	Revised Vendor guarantee in March 2025	8,175,708	9,084,120	MMBtu	49.05	54.50
		CO	0.24	lb/MMBtu	Boiler MACT CO Limit	8,175,708	9,084,120	MMBtu	993.89	1,104
		VOC	7.00E-03	lb/MMBtu	Vendor guarantee	8,175,708	9,084,120	MMBtu	28.61	31.79
		Pb	4.80E-05	lb/MMBtu	AP-42 Table 1.6-4	8,175,708	9,084,120	MMBtu	0.20	0.22
Total PTE Emissions for CFB Boiler										
Total Scenario PTE		**PM**							**17.61**	**18.65**
		PM_{10}							**112.94**	**121.82**
		$PM_{2.5}$							**103.54**	**111.38**
		NO_X							**396.57**	**391.46**
		SO_2							**49.32**	**54.51**
		CO							**1,048**	**1,106**
		VOC							**31.06**	**31.86**
		Pb							**0.20**	**0.22**
Worst-case Fuel Mix PTE		**PM**							**18.65**	
		PM_{10}							**121.82**	
		$PM_{2.5}$							**111.38**	
		NO_X							**396.57**	
		SO_2							**54.51**	
		CO							**1,106**	
		VOC							**31.86**	
		Pb							**0.22**	

[a] The CFB Boiler and its auxiliary sources will be located at the Altamaha Green Energy (AGE) Facility.

[b] The CFB Boiler natural gas firing rates are based on the following characteristics:

Table A-1
Summary of PTE Emissions for CFB Boiler
New Biomass Boiler Project
(tons/year)

Scenario 1:

HHV (MMBtu/MMscf)	% of Total Annual Boiler Heat Input	Maximum Annual Natural Gas Consumption (MMBtu)	Heat Input (MMBtu/hr)
1,020	10%	908,412	359.00

Scenario 2:

Hours to Startup	# of Startups per Year	Max Hours of Startup per year	Heat Input (MMBtu/hr)
24.00	3.00	72.00	359.00

(c) The CFB Boiler emissions factors from biomass combustion are based on the following characteristics:

Heat Input (MMBtu/hr)	Operating Hours per Year
1,037	8,760

(d) Scenario 1 is defined as 10% of the CFB Boiler's total annual heat input coming from natural gas and 90% of the CFB Boiler's total annual heat input coming from biomass. Scenario 2 assumes the maximum biomass firing rate and assumes a conservative number of natural gas startups (3 total). The worst case PTE was assumed the maximum emissions rate from Scenarios 1 or 2.

Table A-2
Summary of PTE for Auxiliary Sources
New Biomass Boiler Project
(tons/year)

Source Description	Throughput	Pollutant	Emissions Factor	Units	Emissions Factor Source	Throughput	Units	PTE (tpy)
Auxiliary Sources[a]	Bark Hog System	PM	3.90E-05	lb/ton	AP-42 Section 13.2.4 [c]	6,100,161	tons/yr	0.12
		PM_{10}	1.84E-05	lb/ton	AP-42 Section 13.2.4 [c]	6,100,161	tons/yr	5.62E-02
		$PM_{2.5}$	2.79E-06	lb/ton	AP-42 Section 13.2.4 [c]	6,100,161	tons/yr	8.52E-03
	Truck Tipper	PM	3.90E-05	lb/ton	AP-42 Section 13.2.4 [c]	6,100,161	tons/yr	0.12
		PM_{10}	1.84E-05	lb/ton	AP-42 Section 13.2.4 [c]	6,100,161	tons/yr	5.62E-02
		$PM_{2.5}$	2.79E-06	lb/ton	AP-42 Section 13.2.4 [c]	6,100,161	tons/yr	8.52E-03
	Biomass Storage Pile[b]	PM	3.90E-05	lb/ton	AP-42 Section 13.2.4	6,100,161	tons/yr	0.12
		PM_{10}	1.84E-05	lb/ton	AP-42 Section 13.2.4	6,100,161	tons/yr	5.62E-02
		$PM_{2.5}$	2.79E-06	lb/ton	AP-42 Section 13.2.4	6,100,161	tons/yr	8.52E-03
	Sorbent Silo[d]	PM	8.57E-03	lb/hr	Vendor guarantee. Based on air flow rate of 200 SCFM and filter outlet PM grain loading factor of 0.005 gr/ft3.	300.00	hrs/yr	1.29E-03
		PM_{10}	8.57E-03	lb/hr	Conservatively assumed to be equal to PM.	300.00	hrs/yr	1.29E-03
		$PM_{2.5}$	8.57E-03	lb/hr	Conservatively assumed to be equal to PM.	300.00	hrs/yr	1.29E-03
	Sand Silo[e]	PM	4.29E-02	lb/hr	Vendor guarantee. Based on air flow rate of 1,000 SCFM and filter outlet PM grain loading factor of 0.005 gr/ft^3.	8,760	hrs/yr	0.19
		PM_{10}	4.29E-02	lb/hr	Conservatively assumed to be equal to PM.	8,760	hrs/yr	0.19
		$PM_{2.5}$	4.29E-02	lb/hr	Conservatively assumed to be equal to PM.	8,760	hrs/yr	0.19
	Fly Ash Silo[e]	PM	4.29E-02	lb/hr	Vendor guarantee. Based on air flow rate of 1,000 SCFM and filter outlet PM grain loading factor of 0.005 gr/ft^3.	8,760	hrs/yr	0.19
		PM_{10}	4.29E-02	lb/hr	Conservatively assumed to be equal to PM.	8,760	hrs/yr	0.19
		$PM_{2.5}$	4.29E-02	lb/hr	Conservatively assumed to be equal to PM.	8,760	hrs/yr	0.19
	Bottom Ash Handling [f]	PM	2.10E-03	lb/ton	AP-42, Table 11.12-2	80,539	tons/yr	8.46E-02
		PM_{10}	2.10E-03	lb/ton	Conservatively assumed to be equal to PM.	80,539	tons/yr	8.46E-02
		$PM_{2.5}$	2.10E-03	lb/ton	Conservatively assumed to be equal to PM.	80,539	tons/yr	8.46E-02
	Cooling Tower[g]	PM	8.24E-02	lb/hr	Vendor guarantee.	8,760	hrs/yr	0.36
		PM_{10}	4.60E-02	lb/hr	Assumed to be 55.8% of PM per *Calculating Realistic*	8,760	hrs/yr	0.20
		$PM_{2.5}$	1.73E-04	lb/hr	Assumed to be 0.21% of PM per *Calculating Realistic*	8,760	hrs/yr	7.58E-04
	Roadways - Paved[g]	PM	0.31	lb/VMT	AP-42 Section 13.2.1	2,940	VMT/yr	0.45
		PM_{10}	6.11E-02	lb/VMT	AP-42 Section 13.2.1	2,940	VMT/yr	8.98E-02
		$PM_{2.5}$	1.50E-02	lb/VMT	AP-42 Section 13.2.1	2,940	VMT/yr	2.20E-02
	Roadways - Unpaved[g]	PM	4.40	lb/VMT	AP-42 Section 13.2.2	2,940	VMT/yr	6.48
		PM_{10}	1.26	lb/VMT	AP-42 Section 13.2.2	2,940	VMT/yr	1.85
		$PM_{2.5}$	0.13	lb/VMT	AP-42 Section 13.2.2	2,940	VMT/yr	0.18
Diesel Emergency Engine[h]	Operating Hours	PM	0.39	lb/hr	40 CFR §89.112, converted from g/kW-hr to lb/hr.	500	hrs/yr	9.81E-02
		PM_{10}	0.39	lb/hr	Conservatively assumed to be equal to PM.	500	hrs/yr	9.81E-02
		$PM_{2.5}$	0.39	lb/hr	Conservatively assumed to be equal to PM.	500	hrs/yr	9.81E-02
		NO_X	11.62	lb/hr	40 CFR §89.112, converted from g/kW-hr to lb/hr. The NO_X	500	hrs/yr	2.90
		SO_2	2.48	lb/hr	AP-42 Table 3.3-1, converted from lb/hp-hr to lb/hr.	500	hrs/yr	0.62
		CO	6.87	lb/hr	40 CFR §89.112, converted from g/kW-hr to lb/hr.	500	hrs/yr	1.72
		VOC	0.94	lb/hr	40 CFR §89.112, converted from g/kW-hr to lb/hr. The NO_X	500	hrs/yr	0.24
Diesel Fire Pump Engine[h]	Operating Hours	PM	9.37E-02	lb/hr	40 CFR Subpart IIII Table 4, converted from g/kW-hr to lb/hr.	500	hrs/yr	2.34E-02
		PM10	9.37E-02	lb/hr	Conservatively assumed to be equal to PM.	500	hrs/yr	2.34E-02
		PM2.5	9.37E-02	lb/hr	Conservatively assumed to be equal to PM.	500	hrs/yr	2.34E-02
		NO_X	1.73	lb/hr	40 CFR Subpart IIII Table 4, converted from g/kW-hr to lb/hr. The NO_X + NMHC factor from §89.112 was split into NO_X and VOC by multiplying by the fraction of the NO_X factor from AP 42 Chapter 3.3 divided by the sum of the NO_X and VOC factors from AP-42 Chapter 3.3.	500	hrs/yr	0.43
		SO_2	0.58	lb/hr	AP-42 Table 3.3-1, converted from lb/hp-hr to lb/hr.	500	hrs/yr	0.15
		CO	1.64	lb/hr	40 CFR Subpart IIII Table 4, converted from g/kW-hr to lb/hr.	500	hrs/yr	0.41
		VOC	0.14	lb/hr	40 CFR Subpart IIII Table 4, converted from g/kW-hr to lb/hr. The NO_X + NMHC factor from §89.112 was split into NO_X and VOC by multiplying by the fraction of the VOC factor from AP 42 Chapter 3.3 divided by the sum of the NO_X and VOC factors from AP-42 Chapter 3.3.	500	hrs/yr	3.51E-02
Total PTE Emissions		**PM**						**8.22**
		PM_{10}						**2.89**
		$PM_{2.5}$						**0.82**
		NO_x						**3.34**
		SO_2						**0.77**
		CO						**2.13**
		VOC						**0.27**
		Pb						**0.00**

[a] The CFB Boiler and its auxiliary sources will be located at the Altamaha Green Energy (AGE) Facility.

Table A-2
Summary of PTE for Auxiliary Sources
New Biomass Boiler Project
(tons/year)

(b) The biomass storage pile emissions factors are based on the following characteristics:

Operating Hours	TSP Emissions Factor ($lb/hr/ft^2$)	Pile Shape	Cone Radius (ft)	Cone Height (ft)	Lateral Outer Surface Area of Storage Pile (ft^2)
8,760	5.12E-07	Cone	190.00	90.00	125,492

(c) AP-42, 13.2.4, Equation (1) (p13.2.4-4) $E = k \times (0.0032) \times \{\frac{\left(\frac{U}{5}\right)^{1.3}}{\left(\frac{M}{2}\right)^{1.4}}\}$

Chips Throughput (tpy)	k (PM)	k (PM_{10})	k ($PM_{2.5}$)	Mean Wind Speed (mph)	Chip Moisture Content (%)
6,100,161	0.74	0.35	5.30E-02	6.80	50.00

(d) The sorbent silo emissions factors are based on the following characteristics:

Operating Hours per Year	Air Flow Rate (SCFM)	Emissions Rate for Bag Filter (gr/ft^3)
300.00	200.00	5.00E-03

(e) The sand and fly ash silo emissions factors are based on the following characteristics:

Operating Hours per Year	Air Flow Rate (SCFM)	Emissions Rate for Bag Filter (gr/ft^3)
8,760	1,000	5.00E-03

(f) The bottom ash handling system emissions are based on the following characteristics

Bottom Ash Disposed Of (Bins/yr)	Tons/Bin	Tons/yr
6,195	13.00	80,539

(g) The cooling tower emissions factors are based on the following characteristics:

Design Flow Rate (GPM)	Manufacturer Guaranteed Drift Loss	Drift Rate (GPM)	Operating Hours	Total Drift Loss (gal/yr)	Water Density (lb/gal)	Total Drift Loss (ton drift/yr)	TDS (ppm)
42,000	0.00050%	0.21	8,760	110,376	8.34	460.27	784.00

(h) The engine emissions calculations are based on the following characteristics:

Engine	kW	hp	Operating Hours Per Year
Diesel Emergency Engine	890.00	1,211	500
Diesel Fire Pump Engine	212.53	285.00	500

Unit Conversions:

Conversion Factor	Units
60.00	min/hr
7,000	gr/lb
453.59	g/lb
1.34	hp/kW
0.99	hp/bhp

Table A-3
Summary of PTE
New Biomass Boiler Project
(tons/year)

Source[a]	PTE							
	PM	PM_{10}[b]	$PM_{2.5}$[b]	NO_X	SO_2	CO	VOC	Pb
Bark Hog System	0.12	5.62E-02	8.52E-03	--	--	--	--	--
Truck Tipper	0.12	5.62E-02	8.52E-03	--	--	--	--	--
CFB Boiler	18.65	121.82	111.38	396.57	54.51	1,106	31.86	0.22
Biomass Storage Pile	0.12	5.62E-02	8.52E-03	--	--	--	--	--
Sorbent Silo	1.29E-03	1.29E-03	1.29E-03	--	--	--	--	--
Bottom Ash Handling	8.46E-02	8.46E-02	8.46E-02	--	--	--	--	--
Sand Silo	0.19	0.19	0.19					
Fly Ash Silo	0.19	0.19	0.19	--	--	--	--	--
Cooling Tower	0.36	0.20	7.58E-04	--	--	--	--	--
Roadways - Paved	0.45	8.98E-02	2.20E-02	--	--	--	--	--
Roadways - Unpaved	6.48	1.85	0.18	--	--	--	--	--
Emergency Diesel-Driven Feedwater Pump	9.81E-02	9.81E-02	9.81E-02	2.90	0.62	1.72	0.24	--
Fire Water Pump	2.34E-02	2.34E-02	2.34E-02	0.43	0.15	0.41	3.51E-02	--
PTE Totals	**26.87**	**124.71**	**112.19**	**399.90**	**55.28**	**1,108**	**32.13**	**0.22**

[a] The CFB Boiler and its auxiliary sources will be located at the AGE Facility.

[b] PM_{10} and $PM_{2.5}$ include both filterable and condensable portions. PM is only the filterable portion.

Table A-4
Summary of Baseline Actual (BAE) Emissions Rates
New Biomass Boiler Project
(tons/year)

Source	BAE Emissions Rates							
	PM	PM_{10} [b]	$PM_{2.5}$ [b]	NO_X	SO_2	CO	VOC	Pb
Power Boiler No. 3[a]	156.72	163.69	105.45	370.21	32.17	1,168	23.36	4.22E-02
Baseline Periods	**October-14**	**October-14**	**October-14**	**October-14**	**January-18**	**January-19**	**October-14**	**October-14**
	September-16	**September-16**	**September-16**	**September-16**	**December-19**	**December-20**	**September-16**	**September-16**
BAE Totals	**156.72**	**163.69**	**105.45**	**370.21**	**32.17**	**1,168**	**23.36**	**4.22E-02**

[a] Power Boiler No. 3 is located at the Rayonier Performance Fibers, LLC - Jesup, GA Plant (RPF Plant).

[b] PM_{10} and $PM_{2.5}$ include both filterable and condensable portions. PM is only the filterable portion.

Table A-5
Prevention of Significant Deterioration (PSD) Applicability Analysis
New Biomass Boiler Project
(tons/year)

Source	PM	PM_{10} [c]	$PM_{2.5}$ [c]	NO_X	SO_2	CO	VOC	Pb
Potential To Emit (PTE) [a]								
Bark Hog System	0.12	5.62E-02	8.52E-03	--	--	--	--	--
Truck Tipper	0.12	5.62E-02	8.52E-03	--	--	--	--	--
CFB Boiler	18.65	121.82	111.38	396.57	54.51	1,106	31.86	0.22
Biomass Storage Pile	0.12	5.62E-02	8.52E-03	--	--	--	--	--
Sand Silo	0.19	0.19	0.19					
Sorbent Silo	1.29E-03	1.29E-03	1.29E-03	--	--	--	--	--
Bottom Ash Handling	8.46E-02	8.46E-02	8.46E-02	--	--	--	--	--
Fly Ash Silo	0.19	0.19	0.19	--	--	--	--	--
Cooling Tower	0.36	0.20	7.58E-04	--	--	--	--	--
Roadways - Paved	0.45	8.98E-02	2.20E-02	--	--	--	--	--
Roadways - Unpaved	6.48	1.85	0.18	--	--	--	--	--
Emergency Diesel-Driven Feedwater Pump	9.81E-02	9.81E-02	9.81E-02	2.90	0.62	1.72	0.24	--
Fire Water Pump	2.34E-02	2.34E-02	2.34E-02	0.43	0.15	0.41	3.51E-02	--
Total PTE	***26.87***	***124.71***	***112.19***	***399.90***	***55.28***	***1,108***	***32.13***	***0.22***
Baseline Actual Emissions (BAE)								
Power Boiler No. 3 [b][d]	156.72	163.69	105.45	370.21	32.17	1,168	23.36	4.22E-02
Total BAE	***156.72***	***163.69***	***105.45***	***370.21***	***32.17***	***1,168***	***23.36***	***4.22E-02***
Projected Actual Emissions (PAE)								
Power Boiler No. 3 [b][d]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total PAE	***0.00***	***0.00***	***0.00***	***0.00***	***0.00***	***0.00***	***0.00***	***0.00***
Total Project-Related Emissions Increases (PTE - BAE + PAE) [e]	***-129.85***	***-38.98***	***6.75***	***29.69***	***23.11***	***-60***	***8.77***	***0.18***
PSD Significant Emissions Rate	***25***	***15***	***10***	***40***	***40***	***100***	***40***	***0.6***
PSD Significant?	**No**	**No**	**No**	**No**	**No**	**No**	**No**	**No**

[a] The CFB Boiler and its auxiliary equipment will be located at the AGE Facility which will be leased from RPF.

[b] Power Boiler No. 3 is located at the RPF Plant.

[c] PM_{10} and $PM_{2.5}$ include both filterable and condensable portions. PM is only the filterable portion.

[d] Power Boiler No. 3 will be decommissioned following completion of the shakedown period of the CFB Boiler. Therefore, PAE for all pollutants from Power Boiler No. 3 is 0 tons/year.

[e] Pursuant to 40 CFR §51.165(a)(1)(vi), RPF and AGE are taking credit for emissions decreases associated with the decommissioning of Power Boiler No. 3.

[f] Total GHG and CO_2e emissions are not included in this report since PSD cannot be triggered for only GHG emissions per U.S. Supreme Court ruling on June 23, 2014.

As shown in Table A-5, no regulated pollutant emission rate increase is significant to trigger PSD review for the AGE Project.

Regulatory Applicability

The circulating fluidized bed biomass cogeneration boiler (Source Code: B01) is subject to the following rules and regulations:

40 CFR 60, Subpart A – "General Provisions"
40 CFR 60, Subpart Da – "Standards of Performance for Electric Utility Steam Generating Units"
40 CFR 63, Subpart A – General Provisions"
40 CFR 63, Subpart DDDDD – "National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters"

Georgia Rule 391-3-1-.02(2)(d) – "Fuel-Burning Equipment"
Georgia Rule 391-3-1-.02(2)(g) – "Sulfur Dioxide"

Storage Pile (Source Code: SP)

The storage pile stores pre-chipped wood, bark, wood waste, peanut hulls, etc., delivered by a telescoping rubber chute conveyor equipped with a water spray to minimize fugitive emissions. The storage pile is subject to the following rules and regulations:

Georgia Rule 391-3-1-.02(2)(b) – "Visible Emissions."
Georgia Rule 391-3-1-.02(2)(e) – "Particulate Emissions from Manufacturing Processes."
Georgia Rule 391-3-1-.02(2)(n) – "Fugitive Dust."

Sorbent Silo (Source Code: SS)

The sorbent silo stores trona and sodium bicarbonate used to scrub the acid gases, sulfur dioxide and hydrogen chloride, from the flue gas. Particulate matter emission from the silo is controlled by a bin vent filter. The sorbent silo is subject to the following rules and regulations:

Georgia Rule 391-3-1-.02(2)(b) – "Visible Emissions."
Georgia Rule 391-3-1-.02(2)(e) – "Particulate Emissions from Manufacturing Processes."
Georgia Rule 391-3-1-.02(2)(n) – "Fugitive Dust."

Flyash Silo (Source Code: AS)

The fly ash silo stores fly ash collected by the baghouse used to control particulate matter emissions from the circulating fluidized bed cogeneration boiler. Particulate matter emission from the fly ash silo is controlled by a bin vent filter. The fly ash silo is subject to the following rules and regulations:

Georgia Rule 391-3-1-.02(2)(b) – "Visible Emissions."
Georgia Rule 391-3-1-.02(2)(e) – "Particulate Emissions from Manufacturing Processes."
Georgia Rule 391-3-1-.02(2)(n) – "Fugitive Dust."

Bottom Ash Handling (Source Code: AH)

The bottom ash handling stores bottom ash collected from the circulating fluidized bed cogeneration boiler. The bottom ash silo is subject to the following rules and regulations:

Georgia Rule 391-3-1-.02(2)(b) – “Visible Emissions.”
Georgia Rule 391-3-1-.02(2)(e) – “Particulate Emissions from Manufacturing Processes.”
Georgia Rule 391-3-1-.02(2)(n) – “Fugitive Dust.”

Cooling Tower (Source Code: CT)

Steam exiting the steam turbine is condensed via indirect heat transfer using a mechanical draft, counterflow wet cooling tower. Cooling tower drift is minimized to 0.001 percent of the design recirculation rate. The Cooling Tower is subject to the following rules and regulations:

Georgia Rule 391-3-1-.02(2)(b) – “Visible Emissions.”
Georgia Rule 391-3-1-.02(2)(e) – “Particulate Emissions from Manufacturing Processes.”
Georgia Rule 391-3-1-.02(2)(n) – “Fugitive Dust.”

Emergency Generator Engine (Source Code: EE)

This is a compression ignition engine used to generate power when there is a power interruption from the grid. It is a reciprocating internal combustion engine (RICE) firing diesel oil with a design power output of 1,184 brake horsepower. It is a Rolls Royce MTU Model 12V2000G85 that was manufactured in 2024.

The engine is subject to the following rules:

40 CFR 60, Subpart A – “General Provisions”
40 CFR 60, Subpart IIII – “Standards of Performance for Stationary Compression Ignition Internal Combustion Engines”
40 CFR 63, Subpart A - “General Provisions”
40 CFR 63, Subpart ZZZZ - “National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines”

Emergency Fire Pump Engine (Source Code: FPE)

This is a compression ignition engine used to operate the fire pump during periods of power outage or similar emergency conditions. It is a reciprocating internal combustion engine (RICE) firing diesel oil with a design power output of 285 brake horsepower. It is a Cummins Model CFP9E-F50 that was manufactured in 2024.

The engine is subject to the following rules:

40 CFR 60, Subpart A – “General Provisions”
40 CFR 60, Subpart IIII – “Standards of Performance for Stationary Compression Ignition Internal Combustion Engines”
40 CFR 63, Subpart A - “General Provisions”
40 CFR 63, Subpart ZZZZ - “National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines”

Sand Silo

The sand silo stores the sand that is used in the fluidized bed to maintain the function of the bed even during fluctuations in fuel feed. The sand silo is subject to the following rules and regulations:

Georgia Rule 391-3-1-.02(2)(b) – “Visible Emissions.”
Georgia Rule 391-3-1-.02(2)(e) – “Particulate Emissions from Manufacturing Processes.”
Georgia Rule 391-3-1-.02(2)(n) – “Fugitive Dust.”

Bark Hog System

This system hogs bark that is used as fuel in the CFB boiler. The bark hog system is subject to the following rules and regulations:

Georgia Rule 391-3-1-.02(2)(b) – “Visible Emissions.”
Georgia Rule 391-3-1-.02(2)(e) – “Particulate Emissions from Manufacturing Processes.”
Georgia Rule 391-3-1-.02(2)(n) – “Fugitive Dust.”

Truck Tipper

The truck tipper offloads the biomass used as fuel in the CFB boiler. The truck tipper is subject to the following rules and regulations:

Georgia Rule 391-3-1-.02(2)(b) – “Visible Emissions.”
Georgia Rule 391-3-1-.02(2)(e) – “Particulate Emissions from Manufacturing Processes.”
Georgia Rule 391-3-1-.02(2)(n) – “Fugitive Dust.”

Permit Conditions

Pursuant to PSD avoidance and Georgia Rule (g), Condition 2.1 limits sulfur dioxide (SO_2) emissions from the Biomass Cogeneration Boiler (Source Code: B01) to 0.012 lb/MMBtu on a 30-day rolling average basis excluding periods of startup, shutdown, and malfunction.

Pursuant to PSD avoidance and Georgia Rule (d), Condition 2.2 limits nitrogen oxides (NOx) emissions from the Biomass Cogeneration Boiler (Source Code: B01) to 0.0859 lb/MMBtu on a 30-day rolling average basis excluding periods of startup, shutdown, and malfunction.

Pursuant to PSD avoidance and Georgia Rule (d), Condition 2.3 limits particulate matter less than 10 microns in diameter (PM_{10}) from the Biomass Cogeneration Boiler (Source Code: B01) to less than 0.0268 lb/MMBtu excluding periods of startup, shutdown, and malfunction.

Pursuant to PSD avoidance and Georgia Rule (d), Condition 2.4 limits particulate matter less than 2.5 microns in diameter ($PM_{2.5}$) from the Biomass Cogeneration Boiler (Source Code: B01) to less than 0.0245 lb/MMBtu excluding periods of startup, shutdown, and malfunction.

Pursuant to PSD avoidance, Condition 2.5 limits carbon monoxide (CO) emissions from the Biomass Cogeneration Boiler (Source Code: B01) to 0.24 lb/MMBtu on a 30-day rolling average basis excluding periods of startup, shutdown, and malfunction.

Pursuant to PSD avoidance, Condition 2.6 limits volatile organic compounds (VOC) emissions from the Biomass Cogeneration Boiler (Source Code: B01) to 0.007 lb/MMBtu excluding periods of startup, shutdown, and malfunction.

Pursuant to PSD avoidance, Condition 2.7 limits lead (Pb) emissions from the Biomass Cogeneration Boiler (Source Code: B01) to 0.000048 lb/MMBtu excluding periods of startup, shutdown, and malfunction.

Condition 2.8 indicates that the Biomass Cogeneration Boiler (Source Code: B01) is subject to 40 CFR 63 Subpart A – "General Provisions" and Subpart DDDDD - "National Emissions Standards for Hazardous Air Pollutants for Industrial Boilers and Process Heaters." This ensures that the Permittee is subject to any required standard that is unintentionally omitted by the permit conditions.

Pursuant to 40 CFR 63.7500(a)(1), Item 9.b., Table 1, Condition 2.9 limits filterable particulate matter emissions from the Biomass Cogeneration Boiler (Source Code: B01) to less than 0.0041 lb/MMBtu of heat input or 0.0050 lb/MMBtu of steam output, excluding periods of startup and shutdown.

Pursuant to 40 CFR 63.7500(a)(1), Item 9.a., Table 1, Condition 2.10 limits Carbon monoxide (CO) emissions from the Biomass Cogeneration Boiler (Source Code: B01) to less than 130 parts per million by volume dry basis (ppmvd) corrected to 3% O_2 on a short-term/3 –hour average basis, 310 ppmvd at 3% O_2 on a 30-day rolling average, or 0.13 lb/MMBtu of steam output on a short-term/3-hour average basis, excluding periods of startup and shutdown.

Pursuant to 40 CFR 63.7500(a)(1), Item 1.a., Table 1, Condition 2.11 limits Hydrogen chloride (HCl) emissions from the Biomass Cogeneration Boiler (Source Code: B01) to less than 0.00021 lb/MMBtu of heat input or 0.00029 lb/MMBtu of steam output, excluding periods of startup and shutdown.

Pursuant to 40 CFR 63.7500(a)(1), Item 1.b., Table 1, Condition 2.12 limits Mercury (Hg) emissions from the CFB Biomass Cogeneration Boiler (Source Code: B01) to less than 8.0E-07 lb/MMBtu of heat input or 8.7E-07 lb/MMBtu of steam output, excluding periods of startup and shutdown.

Pursuant to 40 CFR 60.42Da(b) and 391-3-1-.2(2)(d), Condition 2.13 limit visible emissions from the Biomass Cogeneration Boiler (Source Code: B01) and its associated equipment to less than 20 percent opacity (6-minute average) except for one 6-minute period per hour of not more than 27 percent opacity, except periods of startup, shutdown, or malfunction.

[Note that pursuant to Subpart Da, the Biomass Cogeneration Boiler (Source Code: B01) is exempt from the opacity standard if the Permittee elects to install a CEMS for measuring PM emissions. If the Permittee elects to install a PM CPMS, it is subject to the opacity standard but not required to install a COMS for measuring opacity.]

Condition 2.14 indicates that the Biomass Cogeneration Boiler (Source Code: B01) is subject to 40 CFR 60 Subpart A – "General Provisions" and 40 CFR 60 Subpart Da – "Standards of Performance for Electric Utility Steam Generating Units." This ensures that the Permittee is subject to any required standard that is unintentionally omitted by the permit conditions.

Pursuant to 40 CFR 60.42Da(e) and 40 CFR 60.48Da(a), Condition 2.15 limits PM emissions from the Biomass Cogeneration Boiler (Source Code: B01) to 0.090 lb/MWh gross energy output or 0.097 lb/MWh net energy output, except during periods of startups and shutdowns.

Pursuant to 40 CFR 60.43Da(l) and 40 CFR 60.48Da(a), Condition 2.16 limits, at all times, SO_2 emissions from the Biomass Cogeneration Boiler (Source Code: B01) to 1.0 lb/MWh gross energy output or 1.2 lb/MWh net energy output or 3 percent of the potential combustion concentration (97 percent reduction).

Pursuant to 40 CFR 60.44Da(g), 40 CFR 60.45Da(b), and 40 CFR 60.48Da(a), Condition 2.17 limits, at all times, NOx emissions from the CFB Boiler (Source Code: B01) to 0.70 lb/MWh gross energy output or 0.76 lb/MWh net energy output. Alternatively, the Biomass Cogeneration Boiler (Source Code: B01) can comply with a combined NOx plus CO limit of 1.1 lb/MWh gross energy output or 1.2 lb/MWh (0.3517 lb/MMBtu) net energy output.

Pursuant to 40 CFR 60 Subparts A and IIII, and 40 CFR 1039.101 - Table 1, Condition No. 2.18 requires the Emergency Generator Engine (Source Code: EE) to comply with the requirements of these standards and to not discharge into the atmosphere any emissions in excess of those indicated in the condition.

Pursuant to 40 CFR 60 Subparts A and IIII; 40 CFR 60.4202(d) and 4205(c) - Table 4, Condition No. 2.19 requires Fire Pump Engine (Source Code: FPE) to comply with these standards and to not discharge into the atmosphere any emissions in excess of those indicated in the condition.

Pursuant to 40 CFR 60.4207(b) and 40 CFR 80.510(b); Condition No. 2.20 requires the Permittee to use, for the Emergency Generator Engine (Source Code: EE) and the Fire Pump Engine (Source Code: FPE), ultra-low sulfur diesel oil that meets a maximum sulfur content, by weight of no greater than 15 parts per million, a minimum Cetane Index of 40, and a maximum Aromatic content by volume of 35 percent.

Condition 2.21 indicates that the Emergency Generator Engine (Source Code: EE) and the Fire Pump Engine (Source Code: FPE) are both subject to 40 CFR 63 Subpart ZZZZ - “National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines.” This ensures that the Permittee is subject to any required standard that is unintentionally omitted by the permit conditions.

Pursuant to 40 CFR 60.4211(f), Condition 2.22 limits to 100 hours of non-emergency operation each of the Emergency Generator Engine (Source Code: EE) and the Fire Pump Engine (Source Code: FPE).

Pursuant to 40 CFR 60.4211(a), Condition 2.23 requires each Emergency Engine (Source Code: EE) and Fire Pump Engine (Source Code: FPE) to be operated and maintained according to the manufacturer’s written specifications/instructions or procedures developed by the Permittee that are approved by the engine manufacturer, over the entire life of the engine.

Pursuant to 391-3-1-.02(6)(b)1 and 40 CFR 60.4209(a), Condition 2.24 requires each Emergency Engine (Source Code: EE) and Fire Pump Engine (Source Code: FPE) to be installed with non-resettable hour meters to record the cumulative total hours of operation.

Pursuant to 391-3-1-.02(2)(e)1(i), Condition 2.25 limits particulate matter emissions from the sorbent silo, the fly ash silo, the biomass storage pile, and the cooling tower each to Georgia Rule (e).

Pursuant to 391-3-1-.02(2)(b)1, Condition 2.26 limits visible emissions from all process equipment to less than 40 percent.

Pursuant to 391-3-1-.02(2)(g)2, Condition 2.27 limits fuel combusted in the Biomass Cogeneration Boiler (Source Code: B01) to 3 percent sulfur by weight.

Pursuant to 391-3-1-.02(6)(b)1, Condition 2.28 defines what constitutes the biomass that can be combusted in the Biomass Cogeneration Boiler (Source Code: B01).

Pursuant to 391-3-1-.02(6)(b)1, Condition 2.29 indicates that apart from startups, shutdowns, and when necessary (when natural gas may be fired up to a capacity of 359 MMBtu/hr), only biomass shall be fired in the Biomass Cogeneration Boiler (Source Code: B01).

Pursuant to 40 CFR 63.7575, Condition 2.30 indicates the scenarios and definitions that are applicable to the Biomass Cogeneration Boiler (Source Code: B01) during startups and shutdowns.

Pursuant to the avoidance of 40 CFR 52.21(j), Condition 2.31 requires the permanent decommission of RPF's No. 3 Power Boiler (Source Code: PB03) no later than 60 days following the completion of the shakedown period for the Biomass Cogeneration Boiler (Source Code: B01).

Pursuant to 391-3-1-.02(2)(n)1, Condition 3.1 requires and identifies reasonable precautions to prevent fugitive dust emissions.

Pursuant to 391-3-1-.02(2)(n)1, Condition 3.2 limits visible emissions from any fugitive dust source to less than twenty percent.

Pursuant to the avoidance of 40 CFR 52.21(j) and 391-3-1-.02(6)(b)1, Condition 4.1 indicates that Selective Non-Catalytic Reduction (SNCR-1) is the technology system required to control NOx emissions from the Biomass Cogeneration Boiler (Source Code: B01) stack. SNCR-1 is required to always be in operation except during periods of startup, shutdown, and malfunction and within 13 hours after commencement of combustion of any fuel in the boiler or when the boiler temperature reaches 600°C, whichever occurs first.

Pursuant to the avoidance of 40 CFR 52.21(j) and 391-3-1-.02(6)(b)1, Condition 4.2 indicates that Baghouse (BH-1) is the technology system required to control PM, PM_{10}, and $PM_{2.5}$ emissions from the Biomass Cogeneration Boiler (Source Code: B01) stack. BH-1 is required to always be in operation except during periods of startup, shutdown, and malfunction and within 6 hours after commencement of combustion of any fuel in the boiler.

Pursuant to the avoidance of 40 CFR 52.21(j) and 391-3-1-.02(2)(e), Condition 4.3 indicates that Bin Vent Fabric Filters (VF-1 and VF-2) is the technology system required to control PM emissions from the Sorbent Storage Silo (Source Code: SS) and the Fly Ash Storage Silo (Source Code: AS) stacks. VF-1 and VF-2 are required to always be in operation.

Pursuant to 391-3-1-.03(2)(c), Condition 4.4 requires that an inventory of filter bags be available to replace defective bags to minimize emissions.

Pursuant to 391-3-1-.02(6)(b)1 and 40 CFR 60.48Da, Condition 5.1 requires the Permittee to install, calibrate, maintain, and operate a system that continuously monitors and records the indicated pollutants emissions from the Biomass Cogeneration Boiler (Source Code: B01) in accordance with the applicable performance specification(s) of the Division's monitoring requirements. The CEMS' include that for NOx, SO_2, CO_2 or O_2, and CO. The minimum reportable data period is 90 percent of all operating hours on a 30-boiler operating day rolling average basis.

Pursuant to 391-3-1-.02(6)(b)1, Condition 5.2 requires the Permittee to install, calibrate, maintain, and operate a system that continuously monitors and records the indicated parameters.

Pursuant to 391-3-1-.02(6)(b)1, Condition 5.3 requires a check of the visible emissions from the fabric baghouses and bin vents using the procedures indicated therein.

Pursuant to 391-3-1-.02(6)(b)1, Condition 5.4 requires the Permittee to implement a preventive maintenance program for the bin vent filters and to perform the maintenance checks indicated therein.

Pursuant to 40 CFR 63.7525, Condition 5.5 requires the Permittee to install, certify, operate an oxygen analyzer system, as defined in 40 CFR 63.7575, and maintain continuous emission monitoring systems for CO and oxygen according to the procedures in 40 CFR 63.7525(a)(1) through (7).

Pursuant to 40 CFR 63.7525, Condition 5.6 requires the Permittee to install, operate and maintain all PM CPMS, CEMS, CMS, and all monitoring systems according to the procedures in 40 CFR 63.7525(c) through (m).

Pursuant to 40 CFR 60.49Da(t), Condition 5.7 requires the Permittee to install, calibrate, maintain, and operate a PM Continuous Parameter Monitoring System (PM CPMS) on the Biomass Cogeneration Boiler (Source Code: B01) according to the requirements for new facilities specified in 40 CFR 63, Subpart UUUUU if the Permittee elects to install a PM CPMS.

Pursuant to 40 CFR 60.49Da(t) which references 40 CFR 63.10010(a)(1), h(1-5) and 40 CFR 63.7525(b)(1-4), Condition 5.8 requires the Permittee to install the PM CPMS at a location where the pollutant and diluents concentrations are representative of the emissions that exit to the atmosphere and to operate the PM CPMS and record the output as indicated therein.

Pursuant to 40 CFR 60.49Da(t) which references 40 CFR 63.10010(h)(6) and 40 CFR 63.7535, Condition 5.9 requires that all the data collected during the Biomass Cogeneration Boiler (Source Code: B01) operating hours should be use in assessing the compliance with the Permittee's operating limit except as indicated therein.

Pursuant to 40 CFR 60.49Da(l), (m), Condition 5.10 requires the Permittee to install, certify, operate, and maintain a continuous flow monitoring system meeting the requirements of Performance Specification 6 of appendix B to Part 60 and the calibration drift (CD) assessment, relative accuracy test audit (RATA), and reporting provisions of procedure 1 of appendix F of Part 60, and record the output of the system, for measuring the volumetric flow rate of exhaust gases discharged to the atmosphere or the alternative indicated therein.

Pursuant to 40 CFR 60.49Da(k), Condition 5.11 requires the Permittee to use the procedures indicated therein to determine gross energy output for the Biomass Cogeneration Boiler (Source Code: B01) demonstrating compliance with the PM emissions limit denominated in lb/MWh gross energy output limit.

Pursuant to 40 CFR 60.49Da(t) which references 40 CFR 63.10007 and 40 CFR 63.7525 – Table 6, Condition 5.12 requires the Permittee to establish a site-specific operating limit in units of PM CPMS output signal (e.g., milliamps, mg/acm, or other raw signal) using data from the PM CPMS and the PM performance test according to the procedures indicated therein.

Pursuant to 40 CFR 60.49Da(s) which references 40 CFR 63.10000(d), and 40 CFR 63.7505(d)(1), Condition 5.13 requires the Permittee using CPMS as well as a CEMS to establish a site-specific monitoring plan that addresses the provisions indicated therein at least 45 days before the initial performance evaluation.

Pursuant to 40 CFR 60.49Da(t), Condition 5.14 requires the Permittee demonstrating compliance with the output-based emissions limit to either install, certify, operate, and maintain a CEMS for measuring PM emissions or install, calibrate, operate, and maintain a PM CPMS but if demonstrating compliance with the input-based emissions limit to install, certify, operate, and maintain a CEMS.

Pursuant to 40 CFR 60.49Da(v), Condition 5.15 requires the Permittee using a CEMS measuring PM emissions to meet the requirements of 40 CFR 60 Subpart Da to install, certify, operate, and maintain the CEMS as specified therein.

Pursuant to 40 CFR 60.48Da(f), Condition 5.16 indicates that a Permittee using a PM CEMS demonstrates compliance on a 30-boiler operating day rolling average basis by calculating the arithmetic average of all hourly PM emission rates for the 30 successive boiler operating days, except for data obtained during periods of startup and shutdown.

Pursuant to 40 CFR 60.49Da, 391-3-1-.02(3), and 391-3-1-.03(2)(c), Condition 6.3 requires the Permittee to use CEMS as the compliance determination method for SO_2, NOx, and CO emissions from the Biomass Cogeneration Boiler (Source Code: B01) as indicated therein.

Pursuant to 391-3-1-.02(3) and 391-3-1-.03(2)(c), Condition 6.4 requires the Permittee to conduct a performance test for the Biomass Cogeneration Boiler (Source Code: B01) not later than 180 days after initial startup to verify compliance with the VOC limit.

Pursuant to 391-3-1-.02(3) and 391-3-1-.03(2)(c), Condition 6.5 requires the Permittee to conduct a performance test for the Biomass Cogeneration Boiler (Source Code: B01) not later than 180 days after initial startup to verify compliance with the PM_{10}, $PM_{2.5}$, and Pb limits.

Pursuant to 40 CFR 63.7510, 40 CFR 63.7515, 40 CFR 63.7520, 391-3-1-.02(3), and 391-3-1-.03(2)(c), Condition 6.6 requires the Permittee to conduct a performance test for the Biomass Cogeneration Boiler (Source Code: B01) to verify compliance with the filterable PM limit within the time frame specified by Subpart DDDDD.

Pursuant to 40 CFR 63.7510, 40 CFR 63.7515, 40 CFR 63.7520, 391-3-1-.02(3), and 391-3-1-.03(2)(c), Condition 6.7 requires the Permittee to conduct a performance test for the Biomass Cogeneration Boiler (Source Code: B01) to verify compliance with the CO limit within the time frame specified by Subpart DDDDD.

Pursuant to 40 CFR 63.7510, 40 CFR 63.7515, 40 CFR 63.7520, 391-3-1-.02(3), and 391-3-1-.03(2)(c), Condition 6.8 requires the Permittee to conduct a performance test for the Biomass Cogeneration Boiler (Source Code: B01) to verify compliance with the HCl limit within the time frame specified by Subpart DDDDD.

Pursuant to 40 CFR 63.7510, 40 CFR 63.7515, 40 CFR 63.7520, 391-3-1-.02(3), and 391-3-1-.03(2)(c), Condition 6.9 requires the Permittee to conduct a performance test for the Biomass Cogeneration Boiler (Source Code: B01) to verify compliance with the Hg limit within the time frame specified by Subpart DDDDD.

Pursuant to 40 CFR 63.7515(d) and 40 CFR 63.7540(a)(12), Condition 6.10 requires the Permittee to conduct an annual tune-up every five years not to exceed 61 months from the previous tune-up for the Biomass Cogeneration Boiler (Source Code: B01) to demonstrate continuous compliance.

Pursuant to 40 CFR 60.49Da(t) which references 40 CFR 63.9991(a)(2) and Table 4 of 40 CFR 63 Subpart UUUUU and 40 CFR 60.50Da(b)(1), Condition 6.11 requires the Permittee to maintain the 30-operating day rolling average PM CPMS output value determined through performance testing.

Pursuant to 40 CFR 60.49Da(t) which references 40 CFR 63.10007(a)(3), Condition 6.12 requires the Permittee to maintain the Biomass Cogeneration Boiler (Source Code: B01) at maximum normal operating load defined as generally between 90 and 110 of design capacity during performance testing.

Pursuant to 40 CFR 60.49Da(t) which references 40 CFR 63.10007(c), Condition 6.13 requires the Permittee to establish an operating limit for the Biomass Cogeneration Boiler (Source Code: B01). The Permittee is required to conduct performance testing at other loads to determine additional operating limits should the Permittee desire to have operating limits corresponding to loads other than the maximum.

Pursuant to 40 CFR 60.49Da(t) which references 40 CFR 63.10011(a), (b), and 391-3-1-.02(6)(b)1, Condition 6.14 indicates that the Permittee may establish a site-specific operating limit using parametric data recorded during successful performance tests that demonstrate compliance with the PM limit. The Permittee is also required to demonstrate compliance with the opacity limit concurrently while performing the PM performance test.

Pursuant to 40 CFR 60.49Da(t) which references 40 CFR 63.10023(a), Condition 6.15 requires the Permittee to record all hourly average output values from the PM CPMS for the periods corresponding to the test runs.

Pursuant to 40 CFR 60.49Da(t) which references 40 CFR 63.10023(b)(2)(i), Condition 6.16 requires the Permittee to determine the Biomass Cogeneration Boiler (Source Code: B01) operating limit if the Permittee's performance test indicates that PM emissions do not exceed 75 percent of the limit in Condition 2.15 (0.090 lb/MWh gross energy output or 0.097 lb/MWh net energy output) as indicated therein.

Pursuant to 40 CFR 60.49Da(t) which references 40 CFR 63.10023(b)(2)(ii), Condition 6.17 requires the Permittee to determine the Biomass Cogeneration Boiler (Source Code: B01) operating limit if the Permittee's performance test indicates that PM emissions exceeds 75 percent of the limit in Condition 2.15 (0.090 lb/MWh gross energy output or 0.097 lb/MWh net energy output) as indicated therein.

Pursuant to 40 CFR 60.49Da(t) which references 40 CFR 63.10023(b)(2)(iii-vi), Condition 6.18 requires the Permittee to meet the indicated requirements.

Pursuant to 40 CFR 60.49Da(t) which references 40 CFR 63.10023(c), 40 CFR 63.7525(b), and CFR 63.7540(a)(18), Condition 6.19 requires the Permittee to maintain the Biomass Cogeneration Boiler (Source Code: B01) and control equipment such that the 30-operating day average PM CPMS output does not exceed the established operating limit.

Pursuant to 40 CFR 60.49Da(t) which references 40 CFR 63.10005(d)(2)(iii), 40 CFR 63.7525(b), and CFR 63.7540(a)(18), Condition 6.20 requires the Permittee to repeat the Biomass Cogeneration Boiler (Source Code: B01) PM performance test annually and reassess and adjust the operating limit.

Pursuant to 40 CFR 63.7545(e)(2)(ii), Condition 6.21 requires the Permittee to identify in subsequent performance tests whether the Biomass Cogeneration Boiler (Source Code: B01) is in compliance with the heat input-based or the output-based emission limits in Conditions 2.9 through 2.12.

Pursuant to 40 CFR 60.51Da(i), Condition 7.8.a.i. defines as a reportable excess emission any six-minute average during which the opacity from the Biomass Cogeneration Boiler (Source Code: B01) is equal to or in excess of 20 percent except for one six-minute average per hour of not more than 27 percent opacity.

Condition 7.8.b.i defines as a reportable exceedance whenever fuel fired in the Biomass Cogeneration Boiler (Source Code: B01) is other than natural gas and biomass that meets the definition of biomass in the permit.

Condition 7.8.b.ii defines as a reportable exceedance any heat input to the Biomass Cogeneration Boiler (Source Code: B01) that exceeds 359 MMBtu/hr while firing natural gas.

Condition 7.8.b.iii defines as a reportable exceedance any 30-day rolling average NOx emission rate, which exceeds the limit established by Condition 2.2 for the Biomass Cogeneration Boiler (Source Code: B01).

Condition 7.8.b.iv defines as a reportable exceedance any 30-day rolling CO emission rate, which exceeds the limit established by Condition 2.5 for the Biomass Cogeneration Boiler (Source Code: B01).

Condition 7.8.b.v. defines as a reportable exceedance any 30-day rolling SO_2 emission rate, which exceeds the limit established by Condition 2.1 for the Biomass Cogeneration Boiler (Source Code: B01).

Condition 7.8.c.i defines as a reportable excursion any 30-day rolling average sorbent injection flow rate for each sorbent used measured using the device(s) required by Condition 5.2 that falls below 80 percent of the injection flow rate value established in accordance with Table 7 of 40 CFR 63 Subpart DDDDD.

Condition 7.8.c.ii defines as a reportable excursion any 30-boiler operating day rolling average during which PM CPMS output data for the Biomass Cogeneration Boiler (Source Code: B01) exceeds the operating limit(s) for Subpart Da compliance or Subpart DDDDD compliance established during the initial performance test or subsequent performance tests.

Condition 7.8.c.iii defines as a reportable excursion any PM CPMS deviations from the operating limit leading to more than four required performance tests in a 12-month operating period which constitutes a separate violation of 40 CFR 63 Subpart DDDDD.

Condition 7.8.d.i defines as a reportable incident any time any control equipment required in Conditions 4.1 through 4.4 of the Permit is not in operation or is bypassed while applicable equipment is operating. Periods when the Biomass Cogeneration Boiler (Source Code: B01) control equipment are not in operation or are bypassed shall not be excursions if such periods are exempted per Conditions 4.1 and 4.2.

Condition 7.8.d.ii defines as a reportable incident any weekly inspection of a baghouse as required by Condition 5.4 revealing a problem that is not resolved in accordance with the Preventive Maintenance Program.

Pursuant to 391-3-1-.02(6)(b)1 and 40 CFR 60 Subpart Da, Condition 7.9 requires the Permittee to submit a quarterly report containing the information stated therein.

Pursuant to the avoidance of 40 CFR 52.21(j) and 391-3-1-.02(6)(b)1, Condition 7.10 requires the Permittee to determine compliance using the data acquired by the CEMS in the manner stated therein.

Pursuant to the avoidance of 40 CFR 52.21(j) and 391-3-1-.02(6)(b)1, Condition 7.11 requires the Permittee to maintain daily records of the amounts of fuel and the type of fuel burned to demonstrate compliance with Condition 2.29.

Pursuant to the avoidance of 40 CFR 52.21(j) and 391-3-1-.02(6)(b)1, Condition 7.12 requires the Permittee to maintain the indicated records for the Biomass Cogeneration Boiler (Source Code: B01).

Pursuant to the avoidance of 40 CFR 52.21(j) and 391-3-1-.02(6)(b)1, Condition 7.13 requires the Permittee to verify that the biomass received for combustion complies with the definition of biomass in Condition 2.28.

Pursuant to the avoidance of 40 CFR 52.21(j) and 391-3-1-.02(6)(b)1, Condition 7.14 requires the Permittee to submit a written report of the information indicated for each quarterly period.

Pursuant to 40 CFR 63.7510(g), Condition 7.15 requires the Permittee to complete the required tune-ups.

Pursuant to 40 CFR 63.7545(d), Condition 7.16 requires the Permittee to notify the Division at least 60 days before a performance test is conducted.

Pursuant to 40 CFR 63 Subpart DDDDD, Condition 7.17 requires the Permittee to maintain the indicated records for the Biomass Cogeneration Boiler (Source Code: B01).

Pursuant to 391-3-1-.02(6)(b)1, Condition 7.18 requires the Permittee to retain the indicated records for the emergency engine and the fire pump engine using the hour meters.

Pursuant to 40 CFR 60.52Da(b)(1), Condition 7.19 requires the Permittee to maintain the indicated records for each Method 9 performance test.

Pursuant to 40 CFR 63.7555(b) and 40 CFR 60.49Da(t) which references 40 CFR 63.10032(a)(2), Condition 7.20 requires the Permittee to maintain the indicated PM CPMS records.

Pursuant to 40 CFR 63.7540(a)(18)(ii), Condition 7.21 requires the Permittee to take the indicated actions regarding any deviation from the established operating parameter limit of the 30-boiler operating day rolling PM CPMS average value.

Pursuant to 40 CFR 60.48Da(n), Condition 7.22 specifies the calculation method for the PM emissions discharged into the atmosphere from the Biomass Cogeneration Boiler (Source Code: B01).

Pursuant to the avoidance of 40 CFR 52.21(j), Condition 7.23 requires the Permittee to submit a written notification of the date RPF's No. 3 Power Boiler (Source Code: PB03) is decommissioned within 15 days after such date. The Permittee is required to include in the written notification the date the shakedown period for the Biomass Cogeneration Boiler (Source Code: B01) was completed.

Toxic Impact Assessment

The toxic air pollutants (TAP) – acetaldehyde, acrolein, arsenic, barium, benzene, cadmium, chromium (VI) particulate, chloroform, cobalt, copper, cumene, dibutyl phthalate, 1,2-dichloropropane, ethanol, formaldehyde, n-hexane, mercury, methanol, phenol, phosphorus, propionaldehyde, pyridine, styrene, and toluene are emitted from the facility. Each was modeled to determine whether the maximum ground level concentration (MGLC) exceeded the acceptable ambient concentration (AAC) for the TAP. Below is the table summarizing the modeling results.

TAP	Averaging Period	AAC ($\mu g/m^3$)	Max Modeled Conc. ($\mu g/m^3$)
Acetaldehyde	15-min	4,500	165.5
	Annual	4.55	1.3715
Acrolein	15-min	23	6.190
	Annual	0.35	0.04968
Arsenic	15-min	0.2	0.01067
	Annual	0.000233	0.0001909
Barium	24-hr	1.19	0.05143
Benzene	15-min	1,600	3.807
	Annual	0.13	0.04180
Cadmium	15-min	30	0.001818
	Annual	0.00556	0.00002832
Chloroform	15-min	24,000	20.14
	Annual	0.435	0.2954
Chromium (VI) particulate	Annual	0.1	0.0001140
Cobalt	24-hr	0.24	0.0002127
Copper	24-hr	2.4	0.0009272
Cumene	Annual	400	0.01592
Dibutyl phthalate	24-hr	11.9	0.04652
1,2-dichloropropane	15-min	51,700	0.007537
	Annual	4	0.0002077
Ethanol	24-hr	4,500	0.7408
Formaldehyde	15-min	245	11.36
	Annual	0.0909	**0.1148**
n-Hexane	15-min	17,600	3.297
	Annual	700	0.03856
Mercury	15-min	10	0.001140
	Annual	0.3	0.00002092
Methanol	15-min	32,800	14,657.7
	Annual	20,000	371.3
Phenol	15-min	6,000	73.70
	24-hr	45.2	9.166
Phosphorus	24-hr	0.24	0.08752
Propionaldehyde	Annual	8	0.2961
Pyridine	24-hr	35.7	0.002454
Styrene	15-min	85,200	4.277

TAP	Averaging Period	AAC ($\mu g/m^3$)	Max Modeled Conc. ($\mu g/m^3$)
	Annual	1,000	0.03875
Toluene	15-min	113,000	5.961
	Annual	5,000	0.0644

A review of the table above shows that the facility-wide maximum ground level concentration for formaldehyde exceeds the acceptable ambient concentration. All other TAP were below the AAC. Therefore, residential and business risk assessments were performed for formaldehyde. The following tables show the results of the assessments.

Risk Assessment Residential Area Analysis

TAP	Averaging Period	AAC ($\mu g/m^3$)	Max Modeled Conc. ($\mu g/m^3$)	Receptor UTM Zone: 17	
				Easting (m)	Northing (m)
Formaldehyde	Annual	0.0909	0.06481	419,458.29	3,503,150.06

The table shows that the maximum modeled concentration for formaldehyde is less than the AAC. Therefore, AGE will not have an adverse toxic impact on nearby residential areas.

Risk Assessment Business Area Analysis

TAP	Averaging Period	AAC ($\mu g/m^3$)	Max Modeled Conc. ($\mu g/m^3$)	Receptor UTM Zone: 17	
				Easting (m)	Northing (m)
Formaldehyde	8-hr	3.075*	1.262	419,321.40	3,503,029.02

*8-hour AAC is derived from OSHA's Permissible Exposure Limit of 0.75 ppm using a conversion factor of 1 ppm of formaldehyde = 1.23 mg/m^3 of formaldehyde and a carcinogenic safety factor of 300.

The table shows that the maximum modeled concentration for formaldehyde is less than the AAC. Therefore, AGE will not have an adverse toxic impact on nearby business areas.

Since the residential and business area risk analyses do not indicate any adverse toxic impact, AGE has satisfied the Georgia Air Toxic Guideline.

Summary & Recommendations

It is my recommendation to issue the attached Air Quality Permit No. 4911-305-0039-E-01-0 with conditions which will reasonably ensure that the source is able to demonstrate compliance with our Rules. The public advisory for this source expired on December 11, 2024, and there were comments from Southern Environmental Law Center. The facility is a major source with regard to the Title V rules. The facility is assigned to the Compliance Program for inspection purposes.

Addendum to Narrative

The 30-day public review started on May 7, 2025, and ended on June 9, 2025. Comments were received by the Division from the public, including comments from the Southern Environmental Law Center (SELC) on behalf of itself and 14 others.

Written comments were received on June 9, 2025, from the SELC. The SELC comments have been summarized.

Comment 1
EPD must ensure that issuing a permit for the AGE facility will not lead to an exceedance of national ambient air quality standards (NAAQS).

EPD Response to Comment 1
The Environmental Protection Division (Division) follows the Prevention of Significant Deterioration (PSD) regulations for the construction of new or modified sources of air pollution. The construction of the new Altamaha 1,037 million British thermal unit per hour (MMBtu/hr) Circulating Fluidized Bed (CFB) Biomass Cogeneration Boiler at the Rayonier Performance Fibers, LLC (RPF) facility appeared at first glance to be a major modification of an existing major source subject to the preconstruction review of the PSD regulations because considered alone, the increase in emissions of each of several regulated pollutants; PM, PM_{10}, $PM_{2.5}$, NOx, CO, and SO_2 was significant. However, no net emissions increase was significant to require PSD permitting because RPF's Boiler No. 3 will be decommissioned after a shake-down period of the new boiler. PSD regulations require air quality analysis to demonstrate that any proposed construction will not cause or contribute to a violation of any applicable NAAQS or PSD increment when the modification is subject to PSD rules and regulations. Also, the Altamaha project is not located within 10 kilometers of a Class I area. Therefore, the requirement that any resulting emissions concentration that will increase the 24-hour average concentration of any regulated pollutant in that area by 1 $\mu g/m^3$ or greater does not apply. For these reasons, the Altamaha project does not require NAAQS monitoring. The particulate matter emissions are subject to emissions monitoring using continuous emission monitoring system (CEMS) or continuous parameter monitoring system (CPMS). Any violation of the particulate matter emission limit in the permit will be recorded and corrected quickly by the facility. The facility will be controlling particulate matter emissions using baghouses which are excellent control technology for particulate matter emissions.

EPD has determined that no change will be made to the permit.

Comment 2
The Draft Permit is based on an application that is missing critical information.

EPD Response to Comment 2
The Division is satisfied that it had sufficient information to write the draft permit and requested more information when necessary. For example, the Division requested more information for the baseline actual emission rates (Table A-4) because the Division wanted the facility to show the detailed calculations for each year of the 10-year period used for the baseline actual emissions starting from the fuel usage rates, emission factors, etc. Several times during the permitting process, requests were made for more information when there was need for such information. In this back-and-forth process, the application got better each time. This procedure is not unique to the AGE application.

At the initial stage of an application process, the facility might not have all the information needed to complete the application forms and might still be in the process of selecting the vendors. Also, the equipment design might not be finalized.

The permit requires the facility to conduct performance tests where the vendor supplied emission factors will be proved to show compliance with the emission limits in the permit. Performance testing is conducted to validate the vendor supplied emission factor(s).

EPD has determined that no change will be made to the permit.

Comment 3
EPD should lower the emissions limit for nitrogen oxides (NOx) to be consistent with the NOx limit for a very similar facility in Albany, Georgia.

EPD Response to Comment 3
The AGE permit is not subject to PSD regulations as discussed under comment 1 above. Therefore, the best available control technology (BACT) rules do not apply. Between the Altamaha Green Energy, Jesup and the Albany Green Energy, Albany, the boiler vendors are likely different, hence the difference in vendor guarantees.

EPD has determined that no change will be made to the permit.

Comment 4
The Draft permit is based on toxic air pollution modeling that improperly excludes publicly accessible areas adjacent to the proposed Facility.

EPD Response to Comment 4
AGE and EPD ran additional air dispersion modeling with receptors along Doctortown Road and a specified bend in the Altamaha River directly east from the RPF facility. All results were shown to be similar to those determined previously with only Formaldehyde exceeding the Acceptable Ambient Concentration (AAC). The following reflect the results of EPD's air dispersion modeling.

Table 5-6, updated August 28, 2025

TAP	**Averaging Period**	**AAC ($\mu g/m^3$)**	**Max Modeled Conc. ($\mu g/m^3$)**	
Acetaldehyde	15-min	4,500	174.08881	
	Annual	4.55	1.4337	
Acrolein	15-min	23	6.2583	
	Annual	0.35	0.049897	
Arsenic	15-min	0.2	0.01103	
	Annual	0.000233	0.0001908	
Barium	24-hr	1.19	0.05143	
Benzene	15-min	1,600	3.8974	
	Annual	0.13	0.04202	
Cadmium	15-min	30	0.0019296	
	Annual	0.00556	0.00002831	
Chloroform	15-min	24,000	22.03665	

TAP	Averaging Period	AAC ($\mu g/m^3$)	Max Modeled Conc. ($\mu g/m^3$)
	Annual	0.435	0.2954
Chromium (VI) particulate	Annual	0.1	0.000114
Cobalt	24-hr	0.24	0.0002127
Copper	24-hr	2.4	0.0009272
Cumene	Annual	400	0.01609
Dibutyl phthalate	24-hr	11.9	0.04652
1,2-dichloropropane	15-min	51,700	0.007537
	Annual	4	0.0002077
Ethanol	24-hr	4,500	0.7408
Formaldehyde	15-min	245	11.626
	Annual	0.0909	**0.1163**
n-Hexane	15-min	17,600	3.3155
	Annual	700	0.0386
Mercury	15-min	10	0.001192
	Annual	0.3	0.00002092
Methanol	15-min	32,800	18,391.705
	Annual	20,000	371.8289
Phenol	15-min	6,000	74.2633
	24-hr	45.2	9.2177
Phosphorus	24-hr	0.24	0.08752
Propionaldehyde	Annual	8	0.2972
Pyridine	24-hr	35.7	0.002454
Styrene	15-min	85,200	4.4265
	Annual	1,000	0.03975
Toluene	15-min	113,000	6.2402
	Annual	5,000	0.06516

A review of the table above shows that the facility-wide maximum ground level concentration for formaldehyde exceeds the AAC. All other TAPs were below the AAC. Therefore, residential and business risk assessments were performed for formaldehyde. The following tables show the results of the assessments.

Risk Assessment Residential Area Analysis

TAP	Averaging Period	AAC ($\mu g/m^3$)	Max Modeled Conc. ($\mu g/m^3$)	Receptor UTM Zone: 17	
				Easting (m)	Northing (m)
Formaldehyde	Annual	0.0909	0.06047	419,384.18	3,502,935.32

The table shows that the maximum modeled concentration for formaldehyde is less than the AAC. Therefore, AGE will not have an adverse toxic impact on nearby residential areas.

Risk Assessment Business Area Analysis

TAP	Averaging Period	AAC ($\mu g/m^3$)	Max Modeled Conc. ($\mu g/m^3$)	Receptor UTM Zone: 17	
				Easting (m)	Northing (m)
Formaldehyde	8-hr	3.07*	1.1517	419,351.18	3,502,865.79

*8-hour AAC is derived from OSHA's Permissible Exposure Limit of 0.75 ppm using a conversion factor of 1 ppm of formaldehyde = 1.23 mg/m^3 of formaldehyde and a carcinogenic safety factor of 300.

The table shows that the maximum modeled concentration for formaldehyde is less than the AAC. Therefore, AGE will not have an adverse toxic impact on nearby business areas.

Since the residential and business area risk analyses do not indicate any adverse toxic impact, AGE has satisfied the Georgia Air Toxic Guideline, including the additional receptors along Doctortown Road and the specified bend in the Altamaha River.

EPD has determined that no change will be made to the permit.

Comment 5

The Draft Permit does not include responses to public comments submitted on the AGE Application.

EPD Response to Comment 5

As indicated, the Division requested more information from the facility because of the public advisory comments questioning the basis for the baseline actual emissions calculation (Table A-4) in the application. The facility was asked to submit for each of the 10-year period used for the baseline actual emissions, calculations beginning with the fuel usage rates and emission factors to verify the actual emissions indicated in the table. The Division reviewed the EPA Echo database to verify the actual pollutant emissions in the facility's permit application. Any differences were the result of accounting methodology – calendar year versus baseline average. For example, October 2014 through September 2016 rather than January through December for particulate matter emissions. Additionally, there is a statement in the Narrative that states:

"This permit was written taking into consideration comments received during the public advisory period."

EPD procedures do not require a direct response to comments received during a Public Advisory.

EPD has determined that no change will be made to the permit.

Comment 6

EPD should address additional questions regarding monitoring and compliance provisions in the Draft Permit.

EPD Response to Comment 6

NOx and other emissions during startups and shutdowns are usually excluded from the emissions accounting because those emissions are unstable before steady state is established. The permit requires continuous monitoring of NOx, particulate matter emissions, etc. Therefore, it will be readily obvious when control equipment is not operating.

The permit requires that all testing be conducted in accordance with applicable procedures and methods specified in the Division's Procedures for Testing and Monitoring Sources of Air Pollutants.
The permit requires recordkeeping for the amounts and types of fuel combusted in the boiler.

The permit requires performance testing for lead.

The natural gas firing rate can be determined from the required recordkeeping for natural gas usage. The permit limits the natural gas firing rate.

Power boiler No. 3 has been in operation. The fire at the facility occurred in another part of the facility and did not affect Power Boiler No. 3.

EPD has determined that no change will be made to the permit.

COMMENTS RECEIVED BY EPD FROM MEMBERS OF THE PUBLIC

Comment 7 from Paul A Drawdy, Wayne County Administrator
(Summary of Paul A Drawdy's comments)
As the Wayne County Administrator, I am writing to express my strong support for the Altamaha Green Energy's proposed project to construct a new biomass boiler at the Rayonier Advanced Materials (RYAM) plant in Jesup, Georgia…………

I wholeheartedly endorse Altamaha Green Energy's proposal and urge all relevant stakeholders to support this forward-thinking initiative. It will strengthen RYAM's role as a vital community partner while advancing Wayne County commitment to a cleaner, more sustainable future.

EPD Response to Comment 7
EPD notes the comments from Administrator Paul A Drawdy were received.

EPD has determined that no change will be made to the permit.

Comment 8 from the Georgia Coalition for Environmental Policy and Protection (GCEPP)
(Summary of comments)
The Georgia Coalition for Environmental Policy and Protection (GCEPP) respectfully submits these public comments in response to the draft air quality permit application submitted by Altamaha Green Energy, LLC. The application proposes the construction and operation of a 1,037 MMBtu/hr circulating fluidized bed biomass cogeneration boiler to generate electricity and supply steam to the Rayonier Performance Fibers, LLC facility.

We urge the Georgia Environmental Protection Division (EPD), Air Protection Branch, to withhold any decision on the pending permit application until Altamaha Green Energy conducts and submits an Ambient Air Quality Analysis of the surrounding area. This analysis is critical to ensure protection of public health, particularly due to the expected increase in emissions of nitrogen oxides (NOx), particulate matter (PM), and other harmful pollutants.

Key Concerns:
1. Proximity to Residential Communities
2. Inadequate Emissions Estimates and Permit Review
3. Lack of Best Available Control Technology (BACT) for Key Pollutants

4. Need for an Ambient Air Impact Assessment

We urge EPD to prioritize the health, safety, and environmental quality of Georgia residents—especially those living in close proximity to the proposed facility—before proceeding with final permit approval.

EPD Response to Comment 8
EPD followed the relevant rules and regulations to write the permit. EPD conducted a toxic impact assessment and concluded that there is likely no adverse toxic impact on members of the public. The baseline actual emissions were determined in accordance with both EPD and the EPA regulations and guidance. The regulations allow the facility to select the baseline actual emissions from any consecutive 24-month period in the 10-year period preceding the receipt of the complete application or the beginning of actual construction of the project. The facility selected appropriate technologies available to control emissions from the project; baghouses for particulate matter, selective-non catalytic reduction for NOx, and sorbent injection system for acid gas capture. These control technologies have been classified as BACT in other PSD projects. Ambient impact assessment was not required because the project was not subject to PSD rules and regulations.

EPD has determined that no change will be made to the permit.

Comment 9 from David Pedersen
Good morning Georgia Department of Natural Resources,

I am a Canadian climate and clean-air advocate, and I recently learned to my horror of Georgia Power and Altamaha Green Energy's plans to burn wood (biomass) as part of their electricity generation.

I respectfully ask and urge you to reject the proposal in its entirety for three reasons.

First, burning wood is worse for the climate than burning coal or gas. According to a study by the Partnership for Policy Integrity (PFPI), burning wood emits between 35 and 50% more carbon dioxide than coal, and 230% more carbon dioxide than natural gas, for the same amount of heat output. https://www.pfpi.net/wp-content/uploads/2014/04/PFPI-Biomass-is-the-New-Coal-April-2-2014.pdf

Second, the non-climate air emissions from burning wood are worse than those from coal and gas and are more toxic than cigarette smoke and engine exhaust. Wood smoke has been found to increase the risk of both cancer and dementia more than the emissions from any other fuel source. https://www.dsawsp.org/health/overview

Finally, biomass energy involves logging, which threatens Earth's last intact forests. As more and more species face extinction and the need to sequester carbon and keep it sequestered grows, it is imperative that we leave forests standing - not cut them down to burn them.

In closing, I respectfully urge you to vote NO on Altamaha Green Energy and Georgia Power's proposal to burn wood for electricity. Thank you for your time and consideration.

Regards,

David Pedersen
6744 Welch Road, Saanichton,
British Columbia, Canada V8M 1W6

<u>EPD Response to Comment 9</u>
Absent any regulation proscribing the burning of wood in boilers, EPD followed the regulations for permitting wood-fired boilers. The emissions from this project are controlled using appropriate control technologies.

No change was made to the permit.

<u>Comment 10 from Dawn Thompson</u>
Will this Green Energy project utilize Carbon capture and sequestration storage? Will this project be eligible for 45Q tax credits? Will you release plume modeling to the public showing the vast potential for loss of life due to a breach of the pipelines? How will the river, trees, humidity and wind affect the CO_2 drift will the kill zone be 5 or 10 miles? As this CO_2 is removed from the air and converted to a form that can be transferred through pipeline under extreme pressure passing through our precious water aquifer to hypothetically be stored, will you inform the public what happens to water if there is a breach or fracture? What does carbonic acid due to fish and plant life? How many millions of gallons of water will be needed to control the temperature of the pipelines on a daily basis? As the water for cooling is removed from the deep aquifers and dirtied will it be cleaned and dumped into the river or out on the land If, there is a rupture the CO_2 will make our normal rescue vehicle useless, will these companies provide electric vehicles for all stations in the danger area? What is considered the danger area? What type of monitor will be placed on the well, how will it be monitored. Will you please listen to the first responders as they dealt with the CO_2 leak in Satartia MS.? To destroy trees which clean the air and exchange it for a 45Q tax credit funded project that hasn't worked as promised yet; project by attaching a CC&S and risk water, life and food is an attack on the people. When carbonic acid is introduced into the aquifer how many aquifers are at risk of contamination? The people of Georgia deserve better. The USA deserves better.

Thank you
Dawn Thompson
Sent from Yahoo Mail for iPad

<u>EPD Response to Comment 10</u>
This project does not involve carbon capture or carbon sequestration. Assessment of tax credit eligibility or tax status is not within the purview of the Division.

EPD has determined that no change will be made to the permit.

<u>Comment 11 from Robert Gudea</u>
Hello,

I am writing to formally oppose the air quality permit for the proposed Altamaha Green Energy facility. As the Executive Director of GridEquity, a non-profit organization in South Carolina working to protect communities from the pollution caused by wood pellet plants, I have seen promises broken by wood pellet companies and the unwillingness of state regulatory agencies to uphold state and federal laws.

Here are a few of the issues that I would like to outline...

Inadequate Pollution Assessment
The proposed permit fails to adequately capture the full scope of emissions and environmental impacts from this organic solid fuel combustion facility. The application does not sufficiently address the complete range of pollutants these systems generate, including particulate matter ($PM_{2.5}$ and PM_{10}), nitrogen oxides, volatile organic compounds, black carbon, and carbon monoxide. The permit analysis also fails to account for fugitive emissions from fuel handling, ash management, and material transfer operations that can represent 5-30% of total facility emissions which also includes wood dust.

Missing Impact Categories
Critical environmental and community impacts remain unaddressed in the permit application. The facility will generate substantial noise pollution operating 24 hours a day, 7 days a week from combustion operations, material handling, and continuous truck traffic. Heavy vehicles required for fuel delivery will cause significant damage to local road infrastructure and create ongoing disruption to transportation networks. These same heavy vehicles may delay emergency services response times when roads become congested or damaged. Emergency response capacity becomes particularly critical given that organic solid fuel combustion facilities present inherent fire risks due to the combination of combustible materials and high-heat operations. Fugitive dust from fuel storage, handling operations, and ash disposal will create persistent air quality impacts that extend well beyond the facility boundaries and are poorly captured in traditional stack monitoring and will need water systems to help control the enormous dust plumes from being transferred by the wind.

Cumulative Community Burden
This facility would compound existing pollution burdens in a community that already faces environmental health challenges. The permit fails to conduct meaningful cumulative impact analysis that accounts for how this additional emission-intensive combustion infrastructure will interact with existing pollution sources. Environmental justice principles require assessment of how new facilities affect communities that have already borne disproportionate environmental health impacts.

Economic Impact Misrepresentation
The economic analysis underlying such permit justification does not account for the substantial public health costs this facility will impose on Georgia communities. Medical expenses, increased Medicaid expenditures, lost productivity from respiratory illness, and reduced property values represent significant costs that will far exceed any tax revenue the facility might generate. These externalized costs are borne by communities and taxpayers while profits flow to facility operators.

Recommendation
Our organization in South Carolina is dealing with these same issues, and opposition to these facilities is growing throughout the South as communities witness the enormous harms being documented in North Carolina, Mississippi, Alabama, and Georgia. Based on this regional experience with similar combustion-based energy facilities, I strongly recommend denial of this air quality permit. The application demonstrates insufficient analysis of comprehensive environmental impacts, fails to protect community health and environmental justice, and misrepresents the true economic costs these facilities impose on local communities.

Moreover, it has yet to be proven where any wood pellet facility is able to capture these emissions in an economically viable way and subsequently clarify what they do with it. In other words, is the collected scrubbers burned or dumped in a landfill? This needs to be addressed so the entire lifecycle of this process is understood.

The people of Georgia deserve energy systems that do not compromise public health and environmental quality. This permit should be denied.

Robert Gudea
Founder & Executive Director
gridequity.org/

EPD Response to Comment 11
EPD has addressed all the regulated pollutants emitted by this project in the permit. The permit addressed fugitive emissions by requiring the facility to take all reasonable precautions to prevent fugitive dust from becoming airborne, for example, using water to suppress fugitive dust. The permit limits the opacity from any fugitive dust source to less than 20 percent. EPD conducted a toxic impact assessment to determine the impact on local communities.

EPD has determined that no change will be made to the permit.

Comment 12 from Elizabeth Gomez
I oppose Georgia Power's proposal to install a 70 MW biomass plant in Jesup, Georgia. This plant will harm local residents and increase costs to ratepayers across the state. It fundamentally conflicts with the public interest.

Thank you concerned citizens

Elizabeth Gomez

EPD Response to Comment 12
The Division notes the comments from Elizabeth Gomez were received.

EPD has determined that no change will be made to the permit.

Comment 13 from Josiah 'Jazz' Watts
Dear Mr. Allison,

Please deny Georgia Power's proposal to install a 70 MW biomass plant in Jesup, GA. The proposed biomass-burning plant in Jesup will harm communities. They will pay with their health and income.

Biomass burning produces toxic air pollution. These include particulates (fine dust), carbon monoxide, nitrogen, and other hazardous air pollutants. Pollutants like these cause many health problems. Fine dust, called $PM_{2.5}$, is especially harmful. $PM_{2.5}$ can get into lungs and bloodstreams. $PM_{2.5}$ can hurt lung function, worsen asthma, and cause heart attacks and premature death.

The biomass industry has a history of violations. Every wood pellet plant in Georgia has been in violation of their air permit. The Beasley Group, the owner of FRAM Renewable Energy, is also the owner of Altamaha Green Energy. The Beasley Group has violated their air permits at all five of their locations across our state.

Research has shown that burning biomass is not clean, green, or renewable. Burning wood is a primitive and inefficient energy option. In a blackout during December of 2022, only 63 of 330 MW's of biomass-produced energy was available. This is a 19% efficiency. Based upon the 20% efficiency rate, only 13.3 MW of the planned 70 MW from Altamaha will be available. The majority of the energy will be released as steam which will be sold to Rayonier.

Biomass burners are as dirty and problematic as coal plants. Wood pellets are not carbon neutral. The production and combustion of wood pellets creates 50% more carbon dioxide than coal.

The purpose and responsibility of the GA PSC is to ensure that rates are fair and reasonable. Biomass electricity is costly to ratepayers. This project will cost ratepayers more than 3x the avoided cost. It costs more than other proven renewable energy. Bioenergy has been an expensive failure in other cities. In Gainesville and Austin, biomass operations were money pits.

Logging, which includes logging for wood pellets, is the predominant cause of carbon emissions from US forests. This is more than insects, drought, fire, and wind combined. Logging for wood pellets has clearcut more than 900,000 acres in the US South in the last decade.

I oppose Georgia Power's proposal to install a 70 MW biomass plant in Jesup, Georgia. This plant will harm local residents and increase costs to ratepayers across the state. It fundamentally conflicts with the public interest.

Thank you.
Josiah 'Jazz' Watts
jazzwatts4@gmail.com

EPD Response to Comment 13
Please see various responses to above comments.

EPD has determined that no change will be made to the permit.

Comment 14 from Karen Pruitt

Vote NO!

EPD Response to Comment 14
The Division notes the comment from Karen Pruitt was received.

EPD has determined that no change will be made to the permit.

Comment 15 from Dr. Treva Gear
On behalf of Dogwood Alliance and myself, a Georgia resident, I oppose this costly project. Please deny Georgia Power's proposal to install a 70 MW biomass plant in Jesup, GA. The proposed biomass-burning plant in Jesup will harm communities. They will pay with their health and income. Biomass burning produces toxic air pollution. These include particulates (fine dust), carbon monoxide, nitrogen, and other hazardous air pollutants. Pollutants like these cause many health problems. Fine dust, called PM2.5, is especially harmful. PM2.5 can get into lungs and bloodstreams. PM2.5 can hurt lung function, worsen asthma, and cause heart attacks and premature death.

Cumulative Health Impact

The cumulative impact of the addition of this massive 1,037MMBtu/hr boiler with the current operations will make residents sicker. During a visit to a residential community adjacent to the Rayonier (RYAM)plant, particulate matter from the plant could be seen floating in the air. The smell was pungent and my nose and throat became irritated after a short time being outdoors. After 3-4 hours outside my chest felt heavy. When speaking to residents, they noted that the air quality was not even at its worst at the time of my visit. The addition of AGE's biomass burner will negatively impact the health of residents closest to it and throughout the area. This new, larger biomass boiler will further worsen air quality and harm local residents. The residential communities close to the plant already have high rates of asthma, heart disease, and low life expectancy based upon public health data.

Technical Issues with Air Permit

The PM in the area is almost 10 tons which triggers the need for additional air modeling. AGE has left out critical application information about the equipment and manufacturer they will use. It is not possible for AGE to do accurate modeling without disclosing the equipment and the manufacturer. This makes any estimates about their emissions questionable. A cumulative ambient air study and a Best Available Control Technology (BACT) analysis need to be conducted before considering granting a permit for the AGE biomass boiler. Altamaha Green Energy (AGE) needs to conduct these studies and analyses with Georgia EPD. They must go through the process with public involvement before an air permit is considered for this project. Based on the draft air permit, Altamaha Green Energy will not be using the best available emission control technology to keep the Jesup community residents as safe as possible. Please require that Altmaha Green provide the manufacturer and details of their equipment, do a cumulative ambient air study, and complete a Best Available Control Technology (BACT) analysis before a final air permit is considered.

History of Air Permit Violations by the Beasley Group

The biomass industry has a history of violations. Every wood pellet plant in Georgia has been in violation of their air permit. The Beasley Group, the owner of Beasley Green Power, is part owner of Altamaha Green Energy and also owns multiple wood pellets plants. Since 2012, the Beasley Group has accumulated over 20 violations of their air permits at Hazlehurst Pellets (Hazlehurst, GA), Telfair Forest Products (Lumber City, GA), and Appling Pellets (Baxley, GA). These violations range from failure to use air emission control systems (WESP and RTO) for long periods of time to poor record keeping or lack of reporting.

Biomass is Inefficient and Expensive

Research has shown that burning biomass is not clean or renewable. Burning wood is a primitive and inefficient energy option. In a blackout during December of 2022, only 63 of 330 MW's of biomass-produced energy was available. This is a 19% efficiency. Based upon the 20% efficiency rate, only 13.3 MW of the planned 70 MW from Altamaha will be available. The majority of the energy will be sold to Rayonier. Biomass electricity is costly to ratepayers. This project will cost ratepayers more than 3x the avoided cost. It costs more than other proven renewable energy. Bioenergy has been an expensive failure in other cities. In Gainesville and Austin, biomass operations were money pits.

Environmental Impact

Biomass facilities are controversial because of their impact on the environment. Biomass burners are as dirty and problematic as coal plants. The production and combustion of wood pellets creates 50% more carbon dioxide than coal. Biomass facilities require large amounts of wood to create energy. In the past decade, more than 900,000 acres of forests in the US South have been clearcut to produce wood pellets for biomass.

Conclusion

I urge GA EPD to take action to avoid issuing a permit that harms local residents and costs ratepayers money. Biomass facilities have a history of violating their permits and causing environmental harm. There are better, cleaner, energy solutions that would better serve GA residents.

Thank you,

Dr. Treva Gear, Georgia State Manager, Dogwood Alliance

EPD Response to Comment 15
A baghouse is one of the best control technologies for the control of particulate matter, including $PM_{2.5}$. The permit contains conditions which will ensure the proper operation of the baghouse on the boiler.

The regulations do not require AGE to do ambient modeling analysis. The permit requires AGE to install CEMS or PM CPMS to continuously monitor PM emissions. Any violation of the PM limit in the permit will be readily detected and corrected.

Rayonier Performance Fibers, LLC will be responsible for all permitting and compliance requirements for the AGE facility.

There is no state or Federal regulation that prohibits the burning of biomass in boilers. The Division has permitted the AGE facility based on the rules and regulations available for permitting wood-fired boilers.

EPD has determined that no change will be made to the permit.

Comment 16 from Dr. Treva Gear
Dear Georgia EPD,

The concerned citizens of Cook County are opposed to the draft air permit for Alta Maja green energy . As an EJ community we are well aware of how these biomass industries target poor communities. There are many residents who live adjacent to the Rayonier site where the new massive biomass boiler will be located.

We take issue this permit for the following reasons:

The cumulative impact of the existing Rayonier facility and the added pollution by the Altamaha Green Energy will harm the health of the community. A cumulative ambient air analysis had not been conducted in order to address the true health impact to the Jesup community. Altamaha Green Energy (AGE) has not included the use of the best available control technology to keep pollution as low as possible in this overburdened community. A best available control analysis had not been conducted by AGE. The Beasley Group who owns Beasley Green Power has a history of over 20 air permit violations and 9 OSHA violations at their three wood pellet mills; Appling Pellets (Baxley, GA), Hazlehurst Pellets (Hazlehurst, GA), and Telfair Forest Products (Lumber City, GA). Their air permit violations were for failure to use their pollution controls or failure to report tests. Again, the Concerned Citizens of Cook County are opposed to AGE receiving an air permit. We are opposed to the addition of this biomass boiler which will cause further decline in the Jesup community's air quality and community health.

We request that AGE be required to do a Cumulative Ambient Air Study and a best available control technology analysis before any permit is considered. Both of these studies and analyses need to be conducted under the guidance of the Georgia EPD and through their process with the involvement of the public.

Sincerely,

Dr. Treva Gear, Chair
Concerned Citizens of Cook County
info@joincookcitizens.org

EPD Response to Comment 16
Please see the responses to several comments above, including Comments 1 through 6.

EPD has determined that no change will be made to the permit.

Public Hearing

A public hearing for the proposed circulating fluidized bed biomass cogeneration boiler was held on June 9, 2025. The virtual meeting was facilitated by Zoom web conferencing platform. Nicholas Irwin, communication specialist for the Air Protection Branch started the hearing at 6:05 PM. The purpose of the hearing was to receive comments on the draft construction and operating permit for the proposed boiler from the public. Steve Allison, Program Manager of the Stationary Source Permitting Program, gave a brief presentation of the project prior to receiving comments from the public.

COMMENT 17 from Emily Zucchino, Dogwood Alliance
(Comment is verbatim with some editing)
Thank you. Good evening, everyone. Thank you for this opportunity. Before I give my comment, I did want to confirm one thing, because I think Mr. Allison, in his comments, said the written public comment period ended on the 6th, but I believe people can still turn in written comments until the end of this presentation, correct? Okay, thank you. I just wanted to confirm that.

Thank you again for making this space. My name is Emily Zucchino.

On behalf of Dogwood Alliance, I ask you to please deny Georgia Power's proposal to install a 70 megawatt biomass plant in Jesup. For more than a decade, I have worked alongside communities who have deep concerns about the impacts of biomass facilities on their local health and economy. Based on what I've seen in other communities, this proposed biomass burning plant in Jesup has the potential to harm local residents. They will pay with their health and with their wealth. Burning biomass produces toxic air pollution, as we just saw in the presentation. This includes carbon monoxide, nitrogen, formaldehyde, and other hazardous air pollutants. I understand that this new boiler will create an increase in formaldehyde. I am not a clean air expert, but I do know that there is currently a legal group working with residents, living near biomass facilities who may have been exposed to formaldehyde because of the amount of harm this can cause to human health. So, I encourage any residents who will be living near this facility to just do your research and look into that, and make sure that this is not going to harm your health. Pollutants like these cause many health problems, even in small amounts. Fine dust called $PM_{2.5}$, is especially harmful. Particulate matter can get into lungs and bloodstream, it can hurt lung function, worsen asthma, and cause heart attacks and premature death. The research done by legal experts into this permit highlights concerns. Altamaha Green Energy has left out critical application information about the equipment that they will use. Who will manufacture it, or what emission controls they will use. This makes any estimates about their emissions questionable. Based on the draft air permit, Altamaha Green Energy will not be using the best available emission control technology to keep the Jesup community residents as safe as possible. I ask that Georgia EPD please require that AGE provide the manufacturer in details of their equipment. Do a cumulative ambient air study and complete a best available control technology analysis before a final air permit is considered.

Based on the draft air permit, AG, excuse me, I'm sorry, the biomass industry has had a troubling history of violations. Every biomass plant in Georgia has been in violation of their air permit. The Beasley Group, which is part owner of Altamaha Green Energy, also owns multiple wood pellet plants in the state. Since 2012, the Beasley Group has violated the Air Quality Department's more than 20 times at their plants in Hazelhurst. Lumber City and Baxley. These violations range from failure to use air emission control systems for long periods of time. To poor record keeping or lack of reporting. Research has shown that burning biomass is not clean, green, or renewable. Burning wood is highly inefficient. Biomass electricity is also costly to ratepayers.

This project will cost rate payers more than three times the avoided cost. It costs more than other proven renewable energy, like wind and solar. Bioenergy has been an expensive failure in other cities.

This plant doesn't add any new jobs and will bring nothing to the community other than increased pollution and higher energy rates. Rayonier will continue operating with or without this new boiler.

Our organization opposes Georgia Power's proposal to install a 70 megawatt biomass plant in Jesup, Georgia.

Thank you again for making the time for comments this evening.

<u>EPD Response to Comment 17</u>

There are no state or Federal regulations that prohibit the burning of biomass in boilers. EPD has permitted the AGE facility based on the rules and regulations available for wood-fired boilers. EPD conducted a toxic impact assessment and determined that no adverse public health impact is likely. The permit requires that appropriate air pollution control equipment be used to control the air pollutants. Rayonier Performance Fibers, LLC will be responsible for all permitting and compliance requirements for the AGE facility.

EPD has determined that no change will be made to the permit.

Comment 18 from Peter Slag, SELC
(Comment is verbatim with some editing)
Hi, thank you, can you hear me? Great. Thank you. My name is Peter Slag. I'm an associate attorney with the Southern Environmental Law Center. Thank you for providing this opportunity to comment. I just wanted to point out a couple of things and note that we submitted written comments on behalf of SCLC and several other partner organizations. But I just wanted to highlight a couple of things.

First, Steve Allison, hopefully pointed out that this permitting process involves a kind of emissions accounting that takes the new, large, proposed biomass boiler, and counts up all the projected emissions, and then subtracts from that the quote-unquote actual emissions that have been emitted in the past by the older boiler that's being decommissioned. Now, one problem with that is that the older boilers' actual emissions, in large part, were calculated using emissions reporting from as far back as 2014. So, from a practical perspective, we actually could have a situation where the older boiler already isn't running, or, you know, they've switched capacity to different boilers or different machinery at Rayonier. And, you know, from last year, or the year before, or right now. The old boiler might not actually be emitting very much. Meaning that if you subtract, the older emissions, or from 2014, this look theoretically a much larger number, you're actually sort of creating this false accounting where the new boiler isn't adding all that much new pollution even though it could be adding a lot of new pollution. In fact, on its own, if you just sort of account for the new boiler, and what's actually going to be coming out of the combustion going on inside of that. The new boiler's gonna emit over 100 tons of that very fine particulate matter, PM2.5, that Emily Zucchino pointed out is a tremendous health risk to people who breathe those particles which could be lodged deep in the lungs and can cause cardiac and respiratory diseases.

So, another big pollutant, nitrogen oxides. On its own, the new boiler will emit almost 400 tons, and this was on the table that Mr. Allison presented earlier. So, right now, it says that the old boiler decommissioning will reduce the plant's emissions by, you know, 300 but the reality is that we're not actually sure that the old boiler has emitted anything at all since 2014. In fact, if you go online and look up the emissions from the old boiler, the best you can do is pull up some figures from 2020. There's nothing more recent, so that's a big flaw with this permitting process. And we encourage EPD to deny this process without providing recent information about the old boiler and how much it's actually emitting.

And do a proper accounting for how much the new boiler will lead to an increase in local air pollution emissions. That's one problem. Another, and this is related, is that because the new boiler is going to emit over 100 tons of $PM_{2.5}$, And it's doing so right next to another major source of $PM_{2.5}$, the Rayonier facility. Taken together, those two major sources of $PM_{2.5}$ could have a significant impact on the ambient air concentration of $PM_{2.5}$ and it might implicate the national standard for $PM_{2.5}$, which is set at 9 micrograms per cubic meter. There are already some readings around Jesup in Savannah, Brunswick, and Douglas, Georgia, showing that the $PM_{2.5}$ concentrations in these areas are in these areas are already sort of approaching that limit and particularly in a community that is right next to a big pulping facility, and then we have the added impact of this new boiler. You could see $PM_{2.5}$ emissions go over that National Ambient Air Quality Standard, and that is not allowed under the law. EPD is not allowed to permit a facility that might cause or contribute to such an exceedance. So, as part of this permitting process, we are asking EPD to thoroughly examine whether or not this spoiler will lead to an exceedance due to this new 100 tons of $PM_{2.5}$ emissions.

There's also a very similar biomass facility that emits NOx. It's actually almost the same size, it may be identical, I'm not exactly sure, but that facility has a tighter NOx control standard. EPD shouldn't be permitting this facility with a looser NOx control standard if there's a tighter one that's available and technically feasible. So that's another thing that should be done and if EPD doesn't include that in the permit, it shouldn't issue it.

There's some other issues, that the applicant didn't include makes and models of key control equipment, and didn't supply, gas inlet flows and temperatures and specifications that are all really important to figure out how much pollution is actually going to be emitted, and it's helpful for the public and experts out there to be able to verify that everything is going to be working as intended. EPD should require AGE to provide all the necessary information to do that verification work and for the public to know that everything's going to work as intended and as required under Georgia's air quality laws.

Don't issue this permit unless all the proper steps are taken to make sure that the NAAQS are not exceeded and that the best control technology is used on this facility. Thank you.

EPD Response to Comment 18
Please see various responses to SELC's written comments 1 through 6 above.

EPD has determined that no change will be made to the permit.

Comment 19 from Maggie Van Cantfort of the Altamaha Riverkeeper
(Comment is verbatim with some editing)
Altamaha Riverkeeper signed on to the SELC comments and concurs with the Dogwood Alliance comments made. We are concerned about additional pollutants entering the surface waters by deposition from the air. We would like thorough evaluation of the potential increase in pollution to the area waterways. We also would like to know if the age facility will be required to have separate wastewater or modifying the current RYAM permit.

EPD Response to Comment 19
The permit was written to control air pollution. However, in general, the control of air pollution does minimize water pollution. The current Rayonier permit was amended to remove Power Boiler No. 3 conditions.

EPD has determined that no change will be made to the permit.

The hearing adjourned at 6:32 pm.