PERMIT NO. 4911-305-0039-E-01-0
ISSUANCE DATE: 10/01/2025

GEORGIA
DEPARTMENT OF NATURAL RESOURCES
ENVIRONMENTAL PROTECTION DIVISION

Air Quality Permit

In accordance with the provisions of the Georgia Air Quality Act, O.C.G.A. Section 12-9-1, et seq and the Rules, Chapter 391-3-1, adopted pursuant to and in effect under that Act,

Facility Name:	**Altamaha Green Energy, LLC**
Facility Address:	**4470 Savannah Highway** **Jesup, Georgia 31545, Wayne County**
Mailing Address:	**4470 Savannah Highway** **Jesup, Georgia 31545**
Facility AIRS Number:	**04-13-305-00039**

is issued a Permit for the following:

The Construction and operation of a 1,037 million British thermal unit per hour (MMBtu/hr) Circulating Fluidized Bed (CFB) Biomass Cogeneration Boiler (Source Code: B01) to generate power for the electrical grid and supply steam to the Rayonier Performance Fibers, LLC Kraft pulp mill facility, including a biomass storage pile, a sorbent storage silo, a fly ash storage silo, a bottom ash handling system, a cooling tower, paved and unpaved roadways, a diesel fire pump engine, a diesel emergency engine, a sand silo, a bark hog system, and a truck tipper.

This Permit is conditioned upon compliance with all provisions of The Georgia Air Quality Act, O.C.G.A. Section 12-9-1, et seq, the Rules, Chapter 391-3-1, adopted and in effect under that Act, or any other condition of this Permit.

This Permit may be subject to revocation, suspension, modification or amendment by the Director for cause including evidence of noncompliance with any of the above; or for any misrepresentation made in Application No. 29489 dated October 31, 2024; any other applications upon which this Permit is based; supporting data entered therein or attached thereto; or any subsequent submittals or supporting data; or for any alterations affecting the emissions from this source.

This Permit is further subject to and conditioned upon the terms, conditions, limitations, standards, or schedules contained in or specified on the attached **34** pages.

Jeffrey W. Cown

Jeffrey W. Cown, Director
Environmental Protection Division

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

1. General Requirements

1.1 At all times, including periods of startup, shutdown, and malfunction, the Permittee shall maintain and operate this source, including associated air pollution control equipment, in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Division which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection or surveillance of the source.

1.2 The Permittee shall not build, erect, install or use any article, machine, equipment or process the use of which conceals an emission which would otherwise constitute a violation of an applicable emission standard. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with an opacity standard or with a standard that is based on the concentration of a pollutant in the gases discharged into the atmosphere.

1.3 The Permittee shall submit a Georgia Air Quality Permit application to the Division prior to the commencement of any modification, as defined in 391-3-1-.01(pp), which may result in air pollution and which is not exempt under 391-3-1-.03(6). Such application shall be submitted sufficiently in advance of any critical date involved to allow adequate time for review, discussion, or revision of plans, if necessary. The application shall include, but not be limited to, information describing the precise nature of the change, modifications to any emission control system, production capacity and pollutant emission rates of the plant before and after the change, and the anticipated completion date of the change.

1.4 Unless otherwise specified, all records required to be maintained by this Permit shall be recorded in a permanent form suitable for inspection and submission to the Division and shall be retained for at least five (5) years following the date of entry.

1.5 In cases where conditions of this Permit conflict with each other for any particular source or operation, the most stringent condition shall prevail.

2. Allowable Emissions

2.1 The Permittee shall not cause, let, suffer, permit or allow the emission of sulfur dioxide (SO_2) from the Circulating Fluidized Bed Biomass Cogeneration Boiler (Source Code: B01) in amounts equal to or exceeding 0.012 pound per million Btu (lb/MMBtu) on a 30-day rolling average, excluding periods of startup, shutdown, and malfunction.
[Avoidance of 40 CFR 52.21(j) and 391-3-1-.02(2)(g)1]

2.2 The Permittee shall not cause, let, suffer, permit or allow the emission of nitrogen oxides (NOx) from the Circulating Fluidized Bed Biomass Cogeneration Boiler (Source Code: B01) in amounts equal to or exceeding 0.0859 lb/MMBtu on a 30-day rolling average, excluding periods of startup, shutdown, and malfunction.
[Avoidance of 40 CFR 52.21(j) and 391-3-1-.02(2)(d)4(iii)]

2.3 The Permittee shall not cause, let, suffer, permit or allow the emission of particulate matter (filterable + condensable) less than 10 micrometers in diameter (PM_{10}) from the Biomass Cogeneration Boiler (Source Code: B01) in amounts equal to or exceeding 0.0268 lb/MMBtu, excluding periods of startup, shutdown, and malfunction.
[Avoidance of 40 CFR 52.21(j) and 391-3-1-.02(2)(d)2(iii)]

2.4 The Permittee shall not cause, let, suffer, permit or allow the emission of particulate matter (filterable + condensable) less than 2.5 micrometers in diameter ($PM_{2.5}$) from the Biomass Cogeneration Boiler (Source Code: B01) in amounts equal to or exceeding 0.0245 lb/MMBtu, excluding periods of startup, shutdown, and malfunction.
[Avoidance of 40 CFR 52.21(j) and 391-3-1-.02(2)(d)2(iii)]

2.5 The Permittee shall not cause, let, suffer, permit or allow the emission of carbon monoxide (CO) from the Biomass Cogeneration Boiler (Source Code: B01) in amounts equal to or exceeding 0.24 lb/MMBtu on a 30-day rolling average, excluding periods of startup, shutdown, and malfunction.
[Avoidance of 40 CFR 52.21(j)]

2.6 The Permittee shall not cause, let, suffer, permit or allow the emission of volatile organic compounds (VOC) from the Biomass Cogeneration Boiler (Source Code: B01) in amounts equal to or exceeding 0.007 lb/MMBtu, excluding periods of startup, shutdown, and malfunction.
[Avoidance of 40 CFR 52.21(j)]

2.7 The Permittee shall not cause, let, suffer, permit or allow the emission of Lead (Pb) from the Biomass Cogeneration Boiler (Source Code: B01) in amounts equal to or exceeding 0.000048 lb/MMBtu, excluding periods of startup, shutdown, and malfunction.
[Avoidance of 40 CFR 52.21(j)]

2.8 The Permittee shall comply with the 40 CFR 63, Subpart A "General Provisions" and 40 CFR 63, Subpart DDDDD "National Emissions Standards for Hazardous Air Pollutants for Industrial Boilers and Process Heaters" for operation of the Biomass Cogeneration Boiler (Source Code: B01).
[40 CFR 63 Subparts A and DDDDD]

2.9 The Permittee shall not cause, let, suffer, permit or allow the emission of filterable particulate matter (PM) from the Biomass Cogeneration Boiler (Source Code: B01) in amounts equal to or exceeding 0.0041 lb/MMBtu of heat input or 0.0050 lb/MMBtu of steam output, excluding periods of startup and shutdown.
[Subpart DDDDD - 40 CFR 63.7500(a)(1), Item 9.b., Table 1]

2.10 The Permittee shall not cause, let, suffer, permit or allow the emission of carbon monoxide (CO) from the Biomass Cogeneration Boiler (Source Code: B01) in amounts equal to or exceeding 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.
[Subpart DDDDD - 40 CFR 63.7500(a)(1), Item 9.a., Table 1]

2.11 The Permittee shall not cause, let, suffer, permit or allow the emission of hydrogen chloride (HCl) from the Biomass Cogeneration Boiler (Source Code: B01) in amounts equal to or exceeding 0.00021 lb/MMBtu of heat input or 0.00029 lb/MMBtu of steam output, excluding periods of startup and shutdown.
[Subpart DDDDD - 40 CFR 63.7500(a)(1), Item 1.a., Table 1]

2.12 The Permittee shall not cause, let, suffer, permit or allow the emission of mercury (Hg) from the Biomass Cogeneration Boiler (Source Code: B01) in amounts equal to or exceeding 8.0E-07 lb/MMBtu of heat input or 8.7E-07 lb/MMBtu of steam output, excluding periods of startup and shutdown.
[Subpart DDDDD - 40 CFR 63.7500(a)(1), Item 1.b., Table 1]

2.13 The Permittee shall not cause, let, suffer, permit or allow any visible emissions of which the opacity is equal to or greater than 20 percent opacity (6-minute average) except for one 6-minute period per hour of not more than 27 percent opacity from the Biomass Cogeneration Boiler (Source Code: B01) and its associated equipment, except during periods of startup and shutdown.

The Biomass Cogeneration Boiler (Source Code: B01) is exempt from the opacity standard specified in this condition if the Permittee elects to install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring PM emissions.
[Subpart Da - 40 CFR 60.42Da(b), 40 CFR 40.48Da(a), and 391-3-1-.2(2)(d)]

2.14 The Permittee shall comply with all applicable provisions of the New Source Performance Standards (NSPS) as found in 40 CFR 60 Subpart A - "General Provisions" and 40 CFR 60 Subpart Da - "Standards of Performance for Electric Utility Steam Generating Units" for operation of the Biomass Cogeneration Boiler (Source Code: B01).
[40 CFR 60 Subparts A and Da]

2.15 The Permittee shall limit at all times, except during periods of startup and shutdown, 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.

During startup periods and shutdown periods, the Permittee shall meet the work practice standards specified in Table 3 to 40 CFR 63 Subpart DDDDD.
[Subpart Da - 40 CFR 60.42Da(e) and 40 CFR 60.48Da(a)]

2.16 The Permittee shall limit, at all times, sulfur dioxide (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).
[Subpart Da - 40 CFR 60.43Da(l) and 40 CFR 60.48Da(a)]

2.17 The Permittee shall limit, at all times, nitrogen oxides (NOx) emissions from the Biomass Cogeneration 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 net energy output at all times.
[Subpart Da - 40 CFR 60.44Da(g), 40 CFR 60.45Da(b), and 40 CFR 60.48Da(a)]

2.18 The Permittee shall comply with all applicable provisions of 40 CFR Part 60 New Source Performance Standards (NSPS) Subpart A - "General Provisions" and Subpart IIII – "Standards for Stationary Compression Ignition Internal Combustion Engines", for the Emergency Engine listed in Table 1. The Permittee shall comply with emission standards for non-methane hydrocarbons and nitrogen oxides (NMHC+NOx), carbon monoxide (CO), and particulate matter (PM) as listed below in Table 1 during the useful life of the engine.
[40 CFR 60 Subparts A and IIII; 40 CFR 60.4202(a)(2), 40 CFR 1039 Appendix I, Table 2]

Table 1

	Emission Limit (g/kW-hr)		
Pollutant →	NOx+NMHC	CO	PM
Unit ID: EE (>560 kW)	6.4	3.5	0.2

2.19 The Permittee shall comply with all applicable provisions of 40 CFR Part 60 New Source Performance Standards (NSPS) Subpart A - "General Provisions" and Subpart IIII – "Standards for Stationary Compression Ignition Internal Combustion Engines", for the Fire Pump Engine listed in Table 2. The Permittee shall comply with emission standards for non-methane hydrocarbons and nitrogen oxides (NMHC+NOx), and particulate matter (PM) as listed below in Table 2 during the useful life of the engine.
[40 CFR 60 Subparts A and IIII; 40 CFR 60.4202(d) and 4205(c) - Table 4]

Table 2

Unit ID	Emission Limit (g/kW-hr)	
Pollutant →	NMHC+NOx	PM
Unit ID: FPE (130≤kW<225)	4.0	0.20

2.20 The Permittee shall use diesel fuel for the Emergency Engine (EE) and Fire Pump Engine (FPE) listed in Table 1 and Table 2 that complies with the sulfur content and Cetane Index or aromatic content requirements of 40 CFR 80.510(b) for non-road diesel fuel as follows:
[Subpart IIII - 40 CFR 60.4207(b), 40 CFR 1090.305; 391-3-1-.02(2)(g) subsumed)]

Maximum Sulfur content by weight	Cetane Index OR Aromatic content	
	Minimum Cetane Index	Maximum Aromatic content by volume
15 ppm (0.0015%)	40	35%

2.21 The Permittee shall comply with all applicable provisions of the National Emission Standards for Hazardous Air Pollutants (NESHAP) as found in 40 CFR Part 63 Subpart A – "General Provisions," and Subpart ZZZZ – "National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines" for the operation of the Emergency Engine (Source Code: EE) and Fire Pump Engine (Source Code: FPE) listed in Table 1 and Table 2.
[40 CFR 63 Subparts A and ZZZZ]

2.22 The accumulated non-emergency service (maintenance check and readiness testing) time for Emergency Engine (Source Code: EE) and Fire Pump Engine (Source Code: FPE) listed in Table 1 and Table 2, each shall not exceed 100 hours per year. Any operation other than emergency operation, maintenance check and readiness testing are prohibited.
[Subpart IIII - 40 CFR 60.4211(f)]

2.23 Each Emergency Engine (Source Code: EE) and Fire Pump Engine (Source Code: FPE) listed in Table 1 and Table 2 shall 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. In addition, the Permittee shall only change those settings that are permitted by the manufacturer. The Permittee shall also meet the requirements of 40 CFR Parts 89, 94 and/or 1068 as they apply.
[Subpart IIII - 40 CFR 60.4211(a)]

2.24 The Permittee shall install, calibrate, maintain, and operate non-resettable hour meters on the Emergency Engine (EE) and Fire Pump Engine (FPE) listed in Table 1 and Table 2, to measure and record, during all periods of operation, the cumulative total hours of operation of each engine. Each system shall meet the applicable performance specification(s) of the Division's monitoring requirements.
[391-3-1-.02(6)(b)1 and Subpart IIII - 40 CFR 60.4209(a)]

2.25 The Permittee shall not cause, let, permit, suffer, or allow the rate of emissions from each sorbent silo, fly ash silo, biomass storage pile, and cooling tower, particulate matter in total quantities equal to or exceeding the allowable rate calculated as follows:
[391-3-1-.02(2)(e)1(i)]

$E = 4.1P^{0.67}$; for process input weight rate up to and including 30 tons per hour

$E = 55\ P^{0.11} - 40$; for process input weight rate above 30 tons per hour

Where:

E = emission rate in pounds per hour
P = process input weight rate in tons per hour, excluding moisture

2.26 The Permittee shall not discharge, or cause the discharge, into the atmosphere, from all process equipment, any gases which exhibit visible emissions, the opacity of which is equal to or greater than 40 percent, unless otherwise specified.
[391-3-1-.02(2)(b)1]

2.27 The Permittee shall not burn fuel containing more than 3 percent sulfur, by weight, in the Biomass Cogeneration Boiler (Source Code: B01), unless otherwise specified by the Director.
[391-3-1-.02(2)(g)2]

2.28 For the purposes of this Permit, biomass shall consist of organic matter excluding fossil fuels, including agricultural crops, plants, trees, wood, wood residues, sawmill residue, sawdust, wood chips, bark chips, and forest thinning, harvesting or clearing residues; wood residue from pallets or other wood demolition debris, peanut shells, pecan shells, cotton plants, corn stalk and plant matter including aquatic plants, grasses, stalks, vegetation, and residues including hulls, shells, or cellulose containing fibers.

Any wood waste that has been painted, pigment-stained, or pressure treated with compounds such as chromate copper arsenate, pentachlorophenol, and creosote are not considered biomass. Resinated wood, as defined by 40 CFR 241.2, is considered biomass material when used as a fuel in a combustion unit.
[391-3-1-.02(2)(g)2 and 391-3-1-.02(6)(b)1]

2.29 The Permittee shall only fire biomass or natural gas in the Biomass Cogeneration Boiler (Source Code: B01). Natural Gas combustion shall not exceed the firing rate of 359 MMBtu/hr.
[391-3-1-.02(2)(g)2 and 391-3-1-.02(6)(b)1]

2.30 For the purpose of compliance with conditions associated with 40 CFR 63 Subpart DDDDD of this Permit, the following scenarios and definitions shall be used for the startup and shutdown of the Biomass Cogeneration Boiler (Source Code: B01).
[Subpart DDDDD - 40 CFR 63.7575]

a. Startup and Shutdown definitions in 40 CFR 63.7575.
[40 CFR 63.7575]

b. All continuous monitoring systems must be operated during startup and shutdown.
[Table 3, Items 5 and 6 of 40 CFR 63 Subpart DDDDD]

c. For startup of a boiler, the Permittee shall use natural gas or one of the clean fuels listed in Table 3, Item 5.b. of 40 CFR 63 Subpart DDDDD.
[Table 3, Item 5 of 40 CFR 63 Subpart DDDDD]

d. When firing biomass/bio-based solids, the Permittee shall vent emissions to the main stack(s) and engage all of the applicable control devices during startup and shutdown except limestone injection in fluidized bed combustion boilers, dry scrubber, fabric filter, selective non-catalytic reduction (SNCR), and selective catalytic reduction (SCR). During startup, the Permittee shall start limestone injection in fluidized bed boilers, dry scrubber, fabric filter, SNCR, and SCR systems as expeditiously as possible.
[Table 3, Item 5 of 40 CFR 63 Subpart DDDDD]

e. The Permittee shall comply with all applicable emissions limits at all times except for startup or shutdown periods conforming with this work practice. All monitoring data must be collected during periods of startup and shutdown, as specified in 40 CFR 63.7535(b).
[Table 3, Items 5.d. and 6 of 40 CFR 63 Subpart DDDDD]

2.31 The Permittee shall permanently decommission Rayonier Performance Fiber LLC'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).
[Avoidance of 40 CFR 52.21(j)]

3. Fugitive Emissions

3.1 The Permittee shall take all reasonable precautions to prevent fugitive dust from becoming airborne. Reasonable precautions that should be taken to prevent dust from becoming airborne include, but are not limited to, the following:
[391-3-1-.02(2)(n)1]

a. Use, where possible, of water or chemicals for control of dust in the demolition of existing buildings or structures, construction operations, the grading of roads or the clearing of land;

b. Application of asphalt, water, or suitable chemicals on dirt roads, materials, stockpiles, and other surfaces that can give rise to airborne dusts;

c. Installation and use of hoods, fans, and fabric filters to enclose and vent the handling of dusty materials. Adequate containment methods can be employed during sandblasting or other similar operations;

d. Covering, at all times when in motion, open bodied trucks, transporting materials likely to give rise to airborne dusts; and

e. The prompt removal of earth or other material from paved streets onto which earth or other material has been deposited.

3.2 The percent opacity from any fugitive dust source shall not equal or exceed twenty percent. [391-3-1-.02(2)(n)2]

4. Process & Control Equipment

4.1 To comply with Condition 2.2, the Permittee shall operate a Selective Non-Catalytic Reduction System (Control Device ID: SNCR-1) at the stack of the Biomass Cogeneration Boiler (Source Code: B01). The Permittee shall operate Control Device SNCR-1 at all times the Biomass Cogeneration Boiler (Source Code: B01) is operating except during periods of startup, shutdown, and malfunction; the SNCR will be operated as soon as practicable but no later than when the boiler temperature reaches 600°C or 13 hours after commencement of combustion of any fuel within the boiler, whichever occurs first. Nitrogen oxides emissions must begin being included in averaging periods established under this permit upon startup of the SNCR system. [Avoidance of 40 CFR 52.21(j) and 391-3-1-.02(6)(b)1]

4.2 To comply with Conditions 2.3, 2.4, 2.7, and 2.9, the Permittee shall operate a Baghouse (Control Device ID No. BH-1) at the stack of the Biomass Cogeneration Boiler (Source Code: B01). The Permittee shall operate Control Device BH-1 at all times the Biomass Cogeneration Boiler (Source Code: B01) is operating except during periods of startup, shutdown, and malfunction; the BH-1 will be operated as soon as practicable but no later than 6 hours after commencement of combustion of any fuel in the boiler.
[Avoidance of 40 CFR 52.21(j) and 391-3-1-.02(6)(b)1]

4.3 The Permittee shall operate the following on each silo:
[Avoidance of 40 CFR 52.21(j) and 391-3-1-.02(2)(e)]

a. Sorbent Storage Silo (Source Code: SS) - Bin Vent Fabric Filter (Control Device ID No. VF-2), and

b. Fly Ash Storage Silo (Source Code: AS) – Bin Vent Fabric Filter (Control Device ID No. VF-1),

The Permittee shall operate control equipment listed in a. and b. of this condition at all times, including startup, shutdown, and malfunction.

4.4 The Permittee shall maintain an inventory of filter bags such that an adequate supply of bags is on hand to replace any defective bags in the baghouse and bin vents.
[391-3-1-.03(2)(c)]

5. Monitoring

5.1 The Permittee shall install, calibrate, maintain, and operate a system to continuously monitor and record the indicated pollutants on the following equipment. Each system shall meet the applicable performance specification(s) of the Division's monitoring requirements.
[391-3-1-.02(6)(b)1, 40 CFR 60.48Da, and 40 CFR 63.7525]

a. A Continuous Emissions Monitoring System (CEMS) for measuring NOx emissions discharged to the atmosphere from the Biomass Cogeneration Boiler (Source Code: B01). The output of the CEMS shall be expressed in ppm and pounds per million BTU. The minimum reportable data shall be 90 percent of all operating hours on a 30-boiler operating day rolling average basis.

b. A Continuous Emissions Monitoring System (CEMS) for measuring SO_2 discharged to the atmosphere from the Biomass Cogeneration Boiler (Source Code: B01). The output of the CEMS shall be expressed in ppm and pounds per million BTU. The minimum reportable data shall be 90 percent of all operating hours on a 30-boiler operating day rolling average basis.

c. A Continuous Emissions Monitoring System (CEMS) for measuring O_2 discharged to the atmosphere from the Biomass Cogeneration Boiler (Source Code: B01). The output of the CEMS shall be expressed in ppm and pounds per million BTU. The minimum reportable data shall be 90 percent of all operating hours on a 30-boiler operating day rolling average basis.

d. A Continuous Emissions Monitoring System (CEMS) for measuring CO discharged to the atmosphere from the Biomass Cogeneration Boiler (Source Code: B01). The minimum reportable data shall be 90 percent of all operating hours on a 30-boiler operating day rolling average basis.

e. The Permittee shall, using the procedures of Appendix F, Procedure 1 (Quality Assurance Requirements for Gas Continuous Emissions Monitoring Systems Used for Compliance Determination) contained in the Division's **Procedures for Testing and Monitoring Sources of Air Pollutants**, assess the quality and accuracy of the data acquired by the (CEMS) required by Condition 5.1.a., b., c., and d.

For the purpose of this Permit, an operating day is a 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time. It is not necessary for the fuel to be combusted continuously for the entire 24-hour period. After the first 30-day average, a new 30-day rolling average shall be calculated after each operating day. These records (including calculations) shall be maintained as part of the monthly record suitable for inspection or submittal.

5.2 The Permittee shall install, calibrate, maintain, and operate a system to continuously monitor and record the indicated parameters on the following equipment. Where such performance specification(s) exist, each system shall meet the applicable performance specification(s) of the Division's monitoring requirements.
[391-3-1-.02(6)(b)1 and 40 CFR 63.7525]

a. Monitor to continuously determine the sorbent injection rate for each sorbent used in the Duct Sorbent Injection System (Control Device ID: SI-1) for the Biomass Cogeneration Boiler (Source Code: B01) to demonstrate compliance according to 40 CFR 63.7525(d), 40 CFR 63.7525(i)(1), and 40 CFR 63.7525(i)(2).

b. The heat input to the Biomass Cogeneration Boiler (Source Code: B01). Data shall be recorded hourly.

c. A fuel meter to monitor fuel consumption of natural gas.

5.3 Once each day, or portion of each day of operation, the Permittee shall perform a check for visible emissions from all baghouses and bin vents and inspect emissions units for mechanical problems or malfunction. For any observation of visible emissions, mechanical problems, or malfunctions, the Permittee shall take corrective action and reinspect the equipment to verify that no visible emissions exist and that any mechanical problems or malfunctions have been corrected. The observations and corrective actions shall be recorded in a log and maintained in a condition suitable for inspection by, or submittal to, the Division.
[391-3-1-.02(6)(b)1]

5.4 The Permittee shall implement a Preventive Maintenance Program for the bin vent filters specified in Condition 5.3 to assure that the provisions of Condition 2.25 are met. All QA/QC practices and criteria shall be stated in the Preventive Maintenance Program. The program shall be subject to review and, if necessary to assure compliance, modification by the Division and shall include the pressure drop ranges that indicate proper operation for each baghouse. At a minimum, the following operation and maintenance checks shall be made on at least a monthly basis, and a record of the findings and corrective actions taken shall be kept in a maintenance log:
[391-3-1-.02(6)(b)1]

a. Record the pressure drop across each filter and ensure that it is within the appropriate range.

b. Check dust collector hoppers and conveying systems for proper operation.

5.5 An oxygen analyzer system, as defined in 40 CFR 63.7575, must be installed, operated, and maintained by the Permittee, or the Permittee must install, certify, operate and maintain a continuous emission monitoring systems for CO and O_2 according to the procedures in 40 CFR 63.7525(a)(1) through (6). The Permittee must operate an oxygen trim system with the oxygen level set no lower than the lowest hourly average oxygen concentration measured during the most recent CO performance test as the operating limit for oxygen according to Table 7 to 40 CFR 63, Subpart DDDDD. A plan for complying with this condition shall be included in the compliance plan.
[Subpart DDDDD - 40 CFR 63.7525]

5.6 The Permittee shall install, operate, and maintain all PM CPMS, CEMS, or CMS, and all monitoring systems according to the procedures in 40 CFR 63.7525(c) through (m). A plan for complying with this condition shall be included in the compliance plan.
[Subpart DDDDD - 40 CFR 63.7525]

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

5.8 For the Biomass Cogeneration Boiler (Source Code: B01) that exhausts to the atmosphere through a single dedicated stack, the Permittee shall install the required PM CPMS in the stack or at a location in the ductwork downstream of all emission control devices where the pollutant and diluents concentrations are representative of the emissions that exit to the atmosphere. The Permittee shall operate the PM CPMS and record the output of the system as specified in paragraphs a. through d. below:
[40 CFR 60.49Da(t) which references 40 CFR 63.10010(a)(1), h(1-5), Subpart DDDDD – 40 CFR 63.7525(b)(1-4)]

a. Install, calibrate, operate, and maintain the PM CPMS according to the procedures in the approved site-specific monitoring plan developed in accordance with Condition 5.13, and meet the requirements in paragraphs a.i. through a.iii. of this condition.

   i. The operating principle of the PM CPMS must be based on in-stack or extractive light scatter, light scintillation, beta attenuation, or mass accumulation detection of the exhaust gas or representative sample. The reportable measurement output from the PM CPMS may be expressed as milliamps, stack concentration, or other raw data signal.

   ii. The PM CPMS must have a cycle time (i.e., period required to complete sampling, measurement, and reporting for each measurement) no longer than 60 minutes.

   iii. The PM CPMS must be capable, at a minimum, of detecting and responding to particulate matter concentrations of 0.5 mg/acm.

b. Collect PM CPMS hourly average output data for all boiler operating hours except as indicated in paragraph d. of this condition. Express the PM CPMS output as milliamps, PM concentration, or other raw data signal value.

c. Calculate the arithmetic 30-boiler operating day rolling average of all of the hourly average PM CPMS output collected during all nonexempt boiler operating hours data (e.g., milliamps, PM concentration, raw data signal).

d. The Permittee must collect data using the PM CPMS at all times the Biomass Cogeneration Boiler (Source Code: B01) is operating and at the intervals specified in paragraph a.ii. of this condition, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, required monitoring system quality assurance or quality control activities (including, as applicable, calibration checks and required zero and span adjustments), and any scheduled maintenance as defined in your site-specific monitoring plan.

5.9 The Permittee must use all the data collected during all the Biomass Cogeneration Boiler (Source Code: B01) operating hours in assessing the compliance with the Permittee's operating limit except:
[40 CFR 60.49Da(t) which references 40 CFR 63.10010(h)(6), Subpart DDDDD – 40 CFR 63.7535]

a. Any data collected during periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or quality control activities that temporarily interrupt the measurement of output data from the PM CPMS. The Permittee must report any monitoring system malfunctions or out of control periods in the Permittee's annual deviation reports. The Permittee must report any monitoring system quality assurance or quality control activities per the requirements of 40 CFR 63.10031(b).

b. Any data collected during periods when the monitoring system is out of control as specified in the Permittee's site-specific monitoring plan, repairs associated with periods when the monitoring system is out of control or required monitoring system quality assurance or quality control activities conducted during out-of-control periods. The Permittee must report any such periods in your annual deviation report;

c. Any data recorded during periods of startup or shutdown.

5.10 For the Biomass Cogeneration Boiler (Source Code: B01), demonstrating compliance with Conditions 2.9 and 2.15, the Permittee shall 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

Alternatively, data from a continuous flow monitoring system certified according to the requirements of 40 CFR 75.20(c) and Appendix A to Part 75 and continuing to meet the applicable quality control and quality assurance requirements of 40 CFR 75.21 and Appendix B to Part 75, may be used. Flow rate data reported to meet the requirements of 40 CFR 60.51Da shall not include substitute data values derived from the missing data procedures in Subpart D of Part 75, nor shall the data have been bias adjusted according to the procedures of Part 75.
[Subpart Da – 40 CFR 60.49Da(l), (m)]

5.11 Procedures specified in paragraphs a. through c. of this condition shall be used to determine gross energy output for the Biomass Cogeneration Boiler (Source Code: B01) demonstrating compliance with Condition 2.15.
[Subpart Da - 40 CFR 60.49Da(k)]

a. The Permittee of the Biomass Cogeneration Boiler (Source Code: B01) with electricity generation shall install, calibrate, maintain, and operate a wattmeter; measure gross electrical output in MWh on a continuous basis; and record the output of the monitor.

b. The Permittee of the Biomass Cogeneration Boiler (Source Code: B01) with process steam generation shall install, calibrate, maintain, and operate meters for steam flow, temperature, and pressure; measure gross process steam output in Btu per hour on a continuous basis; and record the output of the monitor.

c. For the Biomass Cogeneration Boiler (Source Code: B01) generating process steam in combination with electrical generation, the gross energy output is determined according to the definition of "gross energy output" specified in 40 CFR 60.41Da that is applicable to the affected facility.

5.12 The Permittee must, for the Biomass Cogeneration Boiler (Source Code: B01), 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 following procedures.
[40 CFR 60.49Da(t) which references 40 CFR 63.10007 and Table 6, Subpart DDDDD – 40 CFR 63.7525]

a. Collect PM CPMS output data during the entire period of the performance tests.

b. Record the average hourly PM CPMS output for each test run in the performance test.

c. Determine the PM CPMS operating limit in accordance with the requirements of Conditions 6.16 through 6.18 from data obtained during the performance test demonstrating compliance with the filterable PM emission limitation in Conditions 2.9 and 2.15 for Subpart Da compliance and the procedure described in 40 CFR 63.7525(b)(1-4) for Subpart DDDDD compliance.

5.13 If the Permittee demonstrates compliance with any applicable emissions limit through use of a continuous monitoring system (CMS), where a CMS includes a continuous parameter monitoring system (CPMS) as well as a continuous emissions monitoring system (CEMS), the Permittee must develop a site-specific monitoring plan and submit this site-specific monitoring plan, if requested, at least 45 days before the initial performance evaluation (where applicable) of the CMS. This requirement to develop and submit a site-specific monitoring plan does not apply to the Biomass Cogeneration Boiler (Source Code: B01) with monitoring plans that apply to CEMS and CPMS prepared under appendix B to part 60 or part 75 of Chapter 40, and that meet the requirements of 40 CFR 63.10010. Using the process described in 40 CFR 63.8(f)(4), the Permittee may request approval of monitoring system quality assurance and quality control procedures alternative to those specified in this condition and, if approved, include those in the Permittee's site-specific monitoring plan. The monitoring plan must address the provisions in paragraphs a. through c. of this condition.
[Subpart Da – 40 CFR 60.49Da(s), (t) which references 40 CFR 63.10000(d), and Subpart DDDDD – 40 CFR 63.7505(d)(1)]

a. The site-specific monitoring plan shall include the information specified in paragraphs c.i. through c.vii. of this condition. Alternatively, the requirements of Paragraphs c.i. through c.vii. are considered to be met for a particular CMS if:

   i. The CMS is installed, certified, maintained, operated, and quality-assured either according to part 75 of Chapter 40, or appendix A or B to 40 CFR 63, Subpart UUUUU; and

   ii. The recordkeeping and reporting requirements of part 75 of Chapter 40, or appendix A or B to 40 CFR 63, Subpart UUUUU, that pertain to the CMS are met.

b. The Permittee must operate and maintain the CMS according to the site-specific monitoring plan.

c. The provisions of the site-specific monitoring plan must address the following items:

   i. Installation of the CMS sampling probe or other interface at a measurement location relative to the Biomass Cogeneration Boiler (Source Code: B01) such that the measurement is representative of control of the exhaust emissions (e.g., on or downstream of the last control device). See 40 CFR 63.10010(a) for further details. For PM CPMS installations, follow the procedures in 40 CFR 63.10010(h).

   ii. Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems.

   iii. Schedule for conducting initial and periodic performance evaluations.

iv. Performance evaluation procedures and acceptance criteria (e.g., calibrations), including the quality control program in accordance with the general requirements of 40 CFR 63.8(d).

v. On-going operation and maintenance procedures, in accordance with the general requirements of 40 CFR 63.8(c)(1)(ii), (c)(3), and (c)(4)(ii).

vi. Conditions that define a CMS that is out of control consistent with 40 CFR 63.8(c)(7)(i) and for responding to out of control periods consistent with 40 CFR 63.8(c)(7)(ii) and (c)(8).

vii. On-going recordkeeping and reporting procedures, in accordance with the general requirements of 40 CFR 63.10(c), (e)(1), and (e)(2)(i), or as specifically required under 40 CFR 63, Subpart UUUUU.

5.14 The Permittee demonstrating compliance with the output-based emissions limit in Condition 2.15 must either install, certify, operate, and maintain a CEMS for measuring PM emissions according to Condition 5.15 or install, calibrate, operate, and maintain a PM CPMS according to Condition 5.7. The Permittee demonstrating compliance with the input-based emissions limit in Condition 2.15 may install, certify, operate, and maintain a CEMS for measuring PM emissions according to the requirements of Condition 5.15.
[Subpart Da – 40 CFR 60.49Da(t)]

5.15 If the Permittee elects to install a PM CEMS, the Permittee using a CEMS measuring PM emissions to meet the requirements of 40 CFR 60 Subpart Da shall install, certify, operate, and maintain the CEMS as specified in paragraphs a. through d. of this condition.
[Subpart Da – 40 CFR 60.49Da(v)]

a. The Permittee shall conduct a performance evaluation of the CEMS according to the applicable requirements of 40 CFR 60.13, Performance Specification 11 in Appendix B of 40 CFR Part 60, and Procedure 2 in Appendix F of 40 CFR Part 60.

b. During each PM correlation testing run of the CEMS required by Performance Specification 11 in Appendix B of 40 CFR Part 60, PM and O_2 (or CO_2) data shall be collected concurrently (or within a 30 to 60-minute period) by both the CEMS and performance tests conducted using the following test methods.

i. For PM, Method 5 or 5B of Appendix A-3 of 40 CFR Part 60 or Method 17 of Appendix A-6 of 40 CFR Part 60; and

ii. For O_2 (or CO_2), Method 3A or 3B of Appendix A-2 of 40 CFR Part 60, as applicable, shall be used.

c. Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with Procedure 2 in Appendix F of this part. Relative Response Audits must be performed annually and Response Correlation Audits must be performed every 3 years.

d. Within 90 days after the date of completing each performance test, as defined in 40 CFR 60.8, conducted to demonstrate compliance with 40 CFR 60, Subpart Da, the Permittee must submit relative accuracy test audit (i.e., reference method) data and performance test (i.e., compliance test) data, except opacity data, electronically to EPA's Central Data Exchange (CDX) by using the Electronic Reporting Tool (ERT) (see http://www.epa.gov/ttn/chief/ert/ert tool.html/) or other compatible electronic spreadsheet. Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into EPA's WebFire database.

5.16 For affected facilities that elect to demonstrate compliance using PM CEMS, compliance with the applicable PM emissions limit in Condition 2.15 is determined 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.
[Subpart Da – 40 CFR 60.48Da(f)]

6. Performance Testing

6.1 The Permittee shall cause to be conducted a performance test at any specified emission point when so directed by the Division. The following provisions shall apply with regard to such tests:

a. All tests shall be conducted and data reduced in accordance with applicable procedures and methods specified in the Division’s Procedures for Testing and Monitoring Sources of Air Pollutants.

b. All test results shall be submitted to the Division within sixty (60) days of the completion of testing.

c. The Permittee shall provide the Division thirty (30) days prior written notice of the date of any performance test(s) to afford the Division the opportunity to witness and/or audit the test, and shall provide with the notification a test plan in accordance with Division guidelines.

d. All monitoring systems and/or monitoring devices required by the Division shall be installed, calibrated and operational prior to conducting any performance test(s). For any performance test, the Permittee shall, using the monitoring systems and/or monitoring devices, acquire data during each performance test run. All monitoring system and/or monitoring device data acquired during the performance testing shall be submitted with the performance test results.

6.2 Performance and compliance tests shall be conducted and data reduced in accordance with applicable procedures and methods specified in the Division's Procedures for Testing and Monitoring Sources of Air Pollutants. The methods for the determination of compliance with emission limits listed under Section 2 (Allowable Emissions) are as follows:
[391-3-1-.02(3)(a)]

a. Method 1 or 1A, as appropriate, shall be used for selection of sampling site and number of traverse points.

b. Method 2 in addition to Method 2A, 2C, 2D, 2F or 2G, as appropriate, shall be used for stack gas flow rate.

c. Method 3, 3A or 3B, as appropriate, shall be used for gas molecular weight.

d. Method 3B shall be used to determine the emissions rate correction factor or excess air. Method 3A may be used as an alternative.

e. Method 4 shall be used for moisture determination.

f. Method 6 or 6C shall be used for the determination of SO_2 concentration.

g. Method 7 or 7E for the determination of nitrogen oxide concentration.

h. Method 9 for the determination of Opacity.

i. Method 10 for the determination of CO concentration.

j. Method 201 or Method 201A in conjunction with Method 202 shall be used to determine the PM_{10}/ $PM_{2.5}$ concentration. The minimum sampling time for each run shall be one hour. Method 5 in conjunction with Method 202 can be used as an alternative.

k. Method 25 or 25A for the determination of VOCs.

l. Method 26 or Method 26A, or approved equivalent shall be used to determine hydrogen chloride (HCl) concentrations; the sampling time for each run shall be one hour.

m. Method 22 shall be used to determine visible fugitive emissions.

n. ASTM E871 or E870, or approved equivalent shall be used to determine biomass moisture content.

o. ASTM E711, or approved equivalent shall be used to determine the heat content of biomass.

p. ASTM E775, or approved equivalent shall be used to determine biomass sulfur content.

q. Method 29, 30A, or 30B, or approved equivalent as specified in Table 5 of 40 CFR Subpart DDDDD for the determination of Mercury (Hg) emissions.

r. Method 5 or 17 for the determination of particulate matter emissions.

Minor changes in methodology may be specified or approved by the Director or his designee when necessitated by process variables, changes in facility design, or improvement or corrections that, in his opinion, render those methods or procedures, or portions thereof, more reliable.

6.3 The Permittee shall use CEMS as the compliance determination method for the Biomass Cogeneration Boiler (Source Code: B01) as follows:
[Subpart Da - 40 CFR 60.49Da, 391-3-1-.02(3), and 391-3-1-.03(2)(c)]

a. The Permittee shall determine compliance with the NOx emission standards in Conditions 2.2 and 2.17 on a continuous basis through the use of a 30-day rolling average emission rate. A new 30-day rolling average emission rate is calculated for each steam generating unit operating period as the average of all of the valid hourly NOx emission data for the preceding 30 steam generating unit operating days and shall exclude periods of startup and shutdown.

b. The Permittee shall determine compliance with the CO emission standards in Condition 2.5 on a continuous basis through the use of a 30-day rolling average emission rate. A new 30-day rolling average emission rate is calculated for each steam generating unit operating day as the average of all of the valid hourly CO emission data for the preceding 30 steam generating unit operating days and shall exclude periods of startup and shutdown.

c. The Permittee shall determine compliance with the SO_2 emission standards in Conditions 2.1 and 2.16 on a continuous basis through the use of a 30-day rolling average emission rate. A new 30-day rolling average emission rate is calculated for each steam generating unit operating day as the average of all of the valid hourly SO_2 emission data for the preceding 30 steam generating unit operating days and shall exclude periods of startup and shutdown.

6.4 The Permittee shall conduct performance testing not later than 180 days after initial startup of the Biomass Cogeneration Boiler (Source Code: B01) using the testing methods in Condition 6.2 for VOC to verify compliance with Condition 2.6 and furnish to the Division a written report of the results of the performance test. Thereafter, performance testing shall be conducted at least once every sixty (60) months.
[391-3-1-.02(3) and 391-3-1-.03(2)(c)]

6.5 The Permittee shall conduct performance testing not later than 180 days after initial startup of the Biomass Cogeneration Boiler (Source Code: B01) using the testing methods in Condition 6.2 for PM_{10}, $PM_{2.5}$, and Pb to verify compliance with Conditions 2.3, 2.4, and 2.7, respectively. Performance testing shall be conducted annually not to exceed thirteen (13) months, at a minimum. If performance tests for two consecutive years are below 75 percent of the permit limit, testing shall be conducted only once every three years, not to exceed 37 months between consecutive tests. If results obtained at such reduced test frequency are 75 percent or higher, testing shall again be required annually until two consecutive tests are less than 75 percent and reduced testing frequency shall again apply.
[391-3-1-.02(3) and 391-3-1-.03(2)(c)]

6.6 The Permittee shall conduct performance testing using the testing methods in Condition 6.2 as specified in Tables 5 and 7 in 40 CFR 63, Subpart DDDDD for the Biomass Cogeneration Boiler (Source Code: B01) for filterable PM to verify compliance with Condition 2.9. The performance testing shall be done initially as within the timeframe specified by 40 CFR 63 Subpart DDDDD. Subsequent testing shall be conducted on an annual basis, except as specified in 40 CFR 63.7515(b), (c), and (g).
[Subpart DDDDD - 40 CFR 63.7510, 40 CFR 63.7515, 40 CFR 63.7520, 391-3-1-.02(3), and 391-3-1-.03(2)(c)]

6.7 The Permittee shall conduct performance testing using the testing methods in Condition 6.2 as specified in Tables 5 and 7 in 40 CFR 63, Subpart DDDDD for the Biomass Cogeneration Boiler (Source Code: B01) for CO to verify compliance with Condition 2.10. Testing shall be conducted on an annual basis, except as specified in 40 CFR 63.7515(b), (c), and (g).

If a CO CEMS that meets the Performance Specifications outlined in 40 CFR 63.7525(a)(3) is used to demonstrate compliance with the applicable alternative CO CEMS emission standard listed in Table 1 of 40 CFR 63 Subpart DDDDD, CO performance tests are not required and the boiler is not subject to the oxygen concentration operating limit requirement specified in 40 CFR 63.7510(a).
[Subpart DDDDD - 40 CFR 63.7510, 40 CFR 63.7515, 40 CFR 63.7520, 391-3-1-.02(3), and 391-3-1-.03(2)(c)]

6.8 The Permittee shall conduct performance testing using the testing methods in Condition 6.2 as specified in Tables 5 and 7 in 40 CFR 63, Subpart DDDDD for the Biomass Cogeneration Boiler (Source Code: B01) for HCl to verify compliance with Condition 2.11. Testing shall be conducted on an annual basis, except as specified in 40 CFR 63.7515(b), (c), and (g).
[Subpart DDDDD - 40 CFR 63.7510, 40 CFR 63.7515, 40 CFR 63.7520, 391-3-1-.02(3), and 391-3-1-.03(2)(c)]

6.9 The Permittee shall conduct performance testing using the testing methods in Condition 6.2 as specified in Tables 5 and 7 in 40 CFR 63, Subpart DDDDD for the Biomass Cogeneration Boiler (Source Code: B01) for Hg to verify compliance with Condition 2.12. Testing shall be conducted on an annual basis, except as specified in 40 CFR 63.7515(b), (c), and (g).
[Subpart DDDDD - 40 CFR 63.7510, 40 CFR 63.7515, 40 CFR 63.7520, 391-3-1-.02(3), and 391-3-1-.03(2)(c)]

6.10 The Permittee shall conduct a tune-up every five years as specified in 63.7540(a)(12) but no more than 61 months after the previous tune-up of the Biomass Cogeneration Boiler (Source Code: B01) to demonstrate continuous compliance.
[Subpart DDDDD - 40 CFR 63.7515(d) and 40 CFR 63.7540(a)(12)]

6.11 The Permittee, demonstrating compliance by using a particulate matter continuous parametric monitoring system (PM CPMS), shall maintain the 30-boiler operating day rolling average PM CPMS output determined in accordance with the requirements of Conditions 6.16 through 6.20 and obtained during the most recent performance test run used in demonstrating compliance with the filterable PM emission limit in Conditions 2.9 and 2.15.
[40 CFR 60.49Da(t) which references 40 CFR 63.9991(a)(2), Table 4; 40 CFR 60.50Da(b)(1)]

6.12 For establishing operating limits with a PM CPMS to demonstrate compliance with a PM emission limit, the Permittee shall operate the Biomass Cogeneration Boiler (Source Code: B01) at maximum normal operating load conditions during the performance test period. Maximum normal operating load will be generally between 90 and 110 percent of design capacity but should be representative of site-specific normal operations during each test run.
[40 CFR 60.49Da(t) which references 40 CFR 63.10007(a)(3)]

6.13 If the Permittee chooses the filterable PM method to comply with the PM emission limit in Conditions 2.9 and 2.15 and demonstrate continuous performance using a PM CPMS, the Permittee must also establish an operating limit according to Conditions 6.14 through 6.19, and Conditions 6.11 and 5.12. Should the Permittee desire to have operating limits that correspond to loads other than maximum normal operating load, the Permittee must conduct testing at those other loads to determine the additional operating limits.
[40 CFR 60.49Da(t) which references 40 CFR 10007(c)]

6.14 The Permittee, subject to Condition 6.11 and using a PM CPMS to demonstrate continuous performance, must also establish a site-specific operating limit in accordance with Condition 6.13 and Table 6 of 40 CFR 63, Subpart UUUUU. The Permittee may use only parametric data recorded during successful performance tests (i.e., tests that demonstrate compliance with Conditions 2.9 and 2.15) to establish an operating limit.

The Permittee must conduct concurrently with the PM performance test, a visible emissions performance test on the Biomass Cogeneration Boiler (Source Code: B01) to demonstrate compliance with the opacity limit in Condition 2.13.
[40 CFR 60.49Da(t) which references 40 CFR 63.10011(a) and (b), 391-3-1-.02(6)(b)1]

6.15 During a performance test of the Biomass Cogeneration Boiler (Source Code: B01) required by Condition 6.14 or any such performance test that demonstrates compliance with Conditions 2.9 and 2.15, the Permittee shall record all hourly average output values (e.g., milliamps, stack concentration, or other raw data signal) from the PM CPMS for the periods corresponding to the test runs (e.g., nine 1-hour average PM CPMS output values for 3-hour test runs).
[40 CFR 60.49Da(t) which references 40 CFR 63.10023(a)]

6.16 The Permittee shall determine the Biomass Cogeneration Boiler (Source Code: B01) operating limit as follows if the Permittee's PM performance test demonstrates that PM emissions do not exceed 75 percent of the PM emissions limit in Condition 2.15. The Permittee will use the average PM CPMS value recorded during the PM compliance test, the milliamp equivalent of zero output from the PM CPMS, and the average PM result of the compliance test to establish the Permittee's operating limit. The Permittee shall calculate the operating limit by establishing a relationship of PM CPMS signal to PM concentration using the PM CPMS instrument zero, the average PM CPMS values corresponding to the three compliance test runs, and the average PM concentration from the Method 5 compliance test with the procedures in paragraphs a. through d. of this condition.
[40 CFR 60.49Da(t) which references 40 CFR 63.10023(b)(2)(i)]

a. Determine the PM CPMS instrument zero output with one of the following procedures.

i. Zero point data for in-situ instruments should be obtained by removing the instrument from the stack and monitoring ambient air on a test bench.

ii. Zero point data for extractive instruments should be obtained by removing the extractive probe from the stack and drawing in clean ambient air.

iii. The zero point can also be obtained by performing manual reference method measurements when the flue gas is free of PM emissions or contains very low PM concentrations (e.g., when the boiler is not operating, but the fans are operating or the boiler is combusting only natural gas) and plotting these with the compliance data to find the zero intercept.

iv. If none of the steps in paragraphs a.i. through a.iii. of this condition are possible, the Permittee must use a zero output value provided by the manufacturer.

b. Determine the PM CPMS instrument average (x) in milliamps, and the average of your corresponding three PM compliance test runs (y), using Equation 1.

$$x = \frac{1}{n}\sum_{i=1}^{n} X_i,\ y = \frac{1}{n}\sum_{i=1}^{n} Y_i \ldots\ldots\ldots\ldots (Eq. 1)$$

Where:

X_i = the PM CPMS data points for run i of the performance test,

Y_i = the PM emissions value (in lb/MWh) for run i of the performance test,

n = the number of data points.

c. With the PM CPMS instrument zero expressed in milliamps, the three run average PM CPMS milliamp value, and the three run average PM emissions value (in lb/MWh) from the compliance runs, determine a relationship of PM lb/MWh per milliamp with Equation 2.

$$R = \frac{y}{(x - z)} \ldots\ldots\ldots\ldots\ldots (Eq. 2)$$

Where:

R = the relative PM lb/MWh per milliamp for the PM CPMS,

y = the three run average PM lb/MWh,

x =the three run average milliamp output from the PM CPMS,

z =the milliamp equivalent of the instrument zero determined from paragraph a. of this condition.

d. Determine the Biomass Cogeneration Boiler (Source Code: B01) 30-day rolling average operating limit using the PM lb/MWh per milliamp value from Equation 2 in Equation 3, below. This sets the Permittee's operating limit at the PM CPMS output value corresponding to 75 percent of the Biomass Cogeneration Boiler (Source Code: B01) emission limit.

$$O_L = z + \frac{(0.75L)}{R} \ldots\ldots\ldots (Eq. 3)$$

Where:

O_L = the operating limit for the PM CPMS on a 30-day rolling average, in milliamps,

L = the Biomass Cogeneration Boiler (Source Code: B01) PM emissions limit (Condition 2.16) in lb/MWh,

Z = the instrument zero in milliamps, determined from paragraph a of this condition, and

R = the relative PM lb/MWh per milliamp for your PM CPMS, from equation 2.

6.17 The Permittee shall determine the Biomass Cogeneration Boiler (Source Code: B01) operating limit as follows if the Permittee's PM performance test demonstrates that PM emissions exceeds 75 percent of the PM emissions limit in Condition 2.15. The Permittee will use the average PM CPMS value recorded during the PM compliance test demonstrating compliance with the PM limit to establish the Permittee's operating limit. The Permittee shall determine the operating limit by averaging the PM CPMS milliamp output corresponding to the three PM performance test runs that demonstrate compliance with the emission limit using Equation 4.
[40 CFR 60.49Da(t) which references 40 CFR 63.10023(b)(2)(ii)]

$$O_h = \frac{1}{n}\sum_{i=1}^{n} X_i \text{.........}(Eq. 4)$$

Where:

X_i = the PM CPMS data points for all runs i,

n = the number of data points, and

O_h = the Biomass Cogeneration Boiler (Source Code: B01) operating limit, in milliamps.

6.18 The Permittee shall meet the following requirements:
[40 CFR 60.49Da(t) which references 40 CFR 63.10023(b)(2)(iii-vi)]

a. The PM CPMS must provide a 4-20 milliamp output and the establishment of its relationship to manual reference method measurements must be determined in units of milliamps.

b. The PM CPMS operating range must be capable of reading PM concentrations from zero to a level equivalent to two times the Permittee's allowable emission limit. If the PM CPMS is an auto-ranging instrument capable of multiple scales, the primary range of the instrument must be capable of reading PM concentration from zero to a level equivalent to two times the Permittee's allowable emission limit.

c. During the initial performance test or any such subsequent performance test that demonstrates compliance with the PM limit, record and average all milliamp output values from the PM CPMS for the periods corresponding to the compliance test runs.

d. For PM performance test reports used to set a PM CPMS operating limit, the electronic submission of the test report must also include the make and model of the PM CPMS instrument, serial number of the instrument, analytical principle of the instrument (e.g. beta attenuation), span of the instruments primary analytical range, milliamp value equivalent to the instrument zero output, technique by which this zero value was determined, and the average milliamp signal corresponding to each PM compliance test run.

6.19 The Permittee must operate and 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 operating limit determined in Conditions 6.15 through 6.17 for Subpart Da compliance and the procedure described in 40 CFR 63.7525(b)(1-4) for Subpart DDDDD compliance.
[40 CFR 60.49Da(t) which references 40 CFR 63.10023(c), Subpart DDDDD – 40 CFR 63.7525(b) and CFR 63.7540(a)(18)]

6.20 The Permittee must repeat the PM performance test annually and reassess and adjust the Biomass Cogeneration Boiler (Source Code: B01) operating limit determined in Conditions 6.15 through 6.17 for Subpart Da compliance and the procedure described in 40 CFR 63.7525(b)(1-4) for Subpart DDDDD compliance in accordance with the results of the performance test.
[40 CFR 60.49Da(t) which references 40 CFR 63.10005(d)(2)(iii), Subpart DDDDD – 40 CFR 63.7525(b) and CFR 63.7540(a)(18)]

6.21 The Permittee shall identify in the subsequent performance tests required in Conditions 6.6 through 6.9, whether the Biomass Cogeneration Boiler (Source Code: B01) is in compliance with the output-based emission limits or the heat input-based emission limits specified in Conditions 2.9 through 2.12.
[Subpart DDDDD – 40 CFR 63.7545(e)(2)(ii)]

7. Notification, Reporting and Record Keeping Requirements

7.1 The Permittee shall submit written notification of startup to the Division within 15 days after such date. The notification shall be submitted to:
Mr. Sean Taylor
Stationary Source Compliance Program
4244 International Parkway, Suite 120
Atlanta GA 30354

7.2 Unless otherwise specified, all records required to be maintained by this Permit shall be recorded in a permanent form suitable for inspection and submission to the Division and to the EPA. The records shall be retained for at least five (5) years following the date of entry.
[391-3-1-.02(6)(b)1(i)]

7.3 In addition to any other reporting requirements of this Permit, the Permittee shall report to the Division in writing, within seven (7) days, any deviations from applicable requirements associated with any malfunction or breakdown of process, fuel burning, or emissions control equipment for a period of four hours or more which results in excessive emissions.

The Permittee shall submit a written report that shall contain the probable cause of the deviation(s), duration of the deviation(s), and any corrective actions or preventive measures taken.
[391-3-1-.02(6)(b)1(iv), 391-3-1-.03(10)(d)1(i)]

7.4 The Permittee shall submit written reports of any failure to meet an applicable emission limitation or standard contained in this permit and/or any failure to comply with or complete a work practice standard or requirement contained in this permit which is not otherwise reported in accordance with Conditions 7.5 or 7.3. Such failures shall be determined through observation, data from any monitoring protocol, or by any other monitoring which is required by this permit. The reports shall cover each semiannual period ending June 30 and December 31 of each year, shall be postmarked by August 29 and February 28, respectively, following each reporting period, and shall contain the probable cause of the failure(s), duration of the failure(s), and any corrective actions or preventive measures taken.
[391-3-1-.03(10)(d)1(i)]

7.5 The Permittee shall submit a written report containing any excess emissions, exceedances, and/or excursions as described in this permit and any monitor malfunctions for each quarterly period ending March 31, June 30, September 30, and December 31 of each year. All reports shall be postmarked by May 30, August 29, November 29, and February 28, respectively, following each reporting period. In the event that there have not been any excess emissions, exceedances, excursions or malfunctions during a reporting period, the report should so state. Otherwise, the contents of each report shall be as specified by the Division's Procedures for Testing and Monitoring Sources of Air Pollutants and shall contain the following:
[391-3-1-.02(6)(b)1]

a. A summary report of excess emissions, exceedances and excursions, and monitor downtime, in accordance with Section 1.5(c) and (d) of the above referenced document, including any failure to follow required work practice procedures.

b. Total process operating time during each reporting period.

c. The magnitude of all excess emissions, exceedances and excursions computed in accordance with the applicable definitions as determined by the Director, any conversion factors used, and the date and time of the commencement and completion of each time period of occurrence.

d. Specific identification of each period of such excess emissions, exceedances, and excursions that occur during startups, shutdowns, or malfunctions of the affected facility. Include the nature and cause of any malfunction (if known), the corrective action taken, or preventive measures adopted.

e. The date and time identifying each period during which any required monitoring system or device was inoperative (including periods of malfunction) except for zero and span checks, and the nature of the repairs, adjustments, or replacement. When the monitoring system or device has not been inoperative, repaired, or adjusted, such information shall be stated in the report.

f. Certification by a Responsible Official that, based on information and belief formed after reasonable inquiry, the statements and information in the report are true, accurate, and complete.

7.6 Where applicable, the Permittee shall keep the following records:
[391-3-1-.03(10)(d)1(i)]

a. The date, place, and time of sampling or measurement;

b. The date(s) analyses were performed;

c. The company or entity that performed the analyses;

d. The analytical techniques or methods used;

e. The results of such analyses; and

f. The operating conditions at the time of sampling or measurement.

7.7 The Permittee shall maintain files of all required measurements, including continuous monitoring systems, monitoring devices, and performance testing measurements; all continuous monitoring system or monitoring device calibration checks; and adjustments and maintenance performed on these systems or devices. These files shall be kept in a permanent form suitable for inspection and shall be maintained for a period of at least five (5) years following the date of such measurements, reports, maintenance and records.
[40 CFR 63.10(b)(1) and 391-3-1-.03(10)(d)1(i)]

7.8 For the purpose of reporting excess emissions, exceedances, and excursions in the report required in Condition 7.5, the following excess emissions, exceedances, and excursions shall be reported:
[391-3-1-.02(6)(b)1]

a. Excess emissions: (means for the purpose of this Condition and Condition 7.5, any condition that is detected by monitoring or record keeping which is specifically defined, or stated to be, excess emissions by an applicable requirement)

   i. 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. [Does not apply if the Permittee elects to install a PM CEMS.]
   [40 CFR 60.51Da(i)]

b. Exceedances: (means for the purpose of this Condition and Condition 7.5, any condition that is detected by monitoring or record keeping that provides data in terms of an emission limitation or standard and that indicates that emissions (or opacity) do not meet the applicable emission limitation or standard consistent with the averaging period specified for averaging the results of the monitoring)

   i. Any time any fuel other than natural gas or biomass that does not meet the definition in Condition 2.28 is fired in Biomass Cogeneration Boiler (Source Code: B01).

ii. Any time natural gas is fired at a rate greater than 359 MMBtu/hr in Biomass Cogeneration Boiler (Source Code: B01).

iii. 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).

iv. Any 30-day rolling CO emission rate which exceeds the limit established by Condition 2.5 for the Biomass Cogeneration Boiler (Source Code: B01).

v. 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)

c. Excursions: (means for the purpose of this Condition and Condition 7.5, any departure from an indicator range or value established for monitoring consistent with any averaging period specified for averaging the results of the monitoring)

i. Any 30-day rolling average sorbent injection flow rate 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.

ii. If the Permittee elects to use a PM CPMS, 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.
[Subpart DDDDD – 40 CFR 63.7540(a)(18)(ii)]

iii. If the Permittee elects to use a PM CPMS, 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.
[Subpart DDDDD – 40 CFR 63.7540(a)(18)(iii)]

d. In addition to the excess emissions, exceedances and excursions specified above, the following should also be included with the report required in Condition 6.1.4:

i. Any time any control equipment required in Condition 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 exceedances if such periods are exempted per Conditions 4.1 and 4.2.

ii. Any weekly inspection of a baghouse/bin vent filter as required by Condition 5.4 revealing a problem that is not resolved in accordance with the Preventive Maintenance Program.

7.9 The Permittee shall submit a quarterly compliance report, which contains the following information:
[391-3-1-.02(6)(b)1, 40 CFR 60 Subpart Da]

a. Company name and address.

b. Statement by a responsible official with that official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report.

c. Date of report and beginning and ending dates of the reporting period.

d. The total fuel used by the Biomass Cogeneration Boiler (Source Code: B01), for each calendar month within the reporting period, including, but not limited to, a description of each fuel and the total fuel usage amount with units of measure.

e. A summary of the results of the performance tests and documentation of any operating limits that were reestablished during this test, if applicable.

f. A signed statement indicating that the Permittee burned only natural gas or biomass as defined in Condition 2.28 in the Biomass Cogeneration Boiler (Source Code: B01).

g. If there were no deviations from any emission limits, operating limits, or work practice standards that apply, a statement indicating that there were no deviations from the emission limits, operating limits, or work practice standards during the reporting period.

h. The 30-boiler operating day rolling average of the milliamps measurement from the PM CPMS.

The first quarterly report must cover the period beginning on the compliance date and ending on March 31, June 30, September 30, or December 31, whichever date is the first date that occurs at the end of the quarter in which initial startup is completed. The quarterly report must be post marked or delivered no later than the 60th day following the end of each reporting period. Each subsequent report must cover the reporting period from January 1 through March 31, April 1 through June 30, July 1 through September 30, or October 1 through December 31 and must be post marked or delivered no later than May 30, August 30, November 30, or February 28, respectively, whichever date is the first date following the end of the quarterly reporting period.

7.10 The Permittee shall determine compliance with the emissions limitations in Conditions 2.1, 2.2, and 2.5 using emissions data acquired by the CEMS. The 30-day rolling average totals shall be determined as follows:
[Avoidance of 40 CFR 52.21(j) and 391-3-1-.02(6)(b)1]

a. For the NOx emission limit required in Condition 2.2, the 30-day average shall be the average of all valid hours of NOx emissions data for any 30 successive operating days. The average shall exclude data from periods of startup and shutdown.

b. For the CO emission limit required in Condition 2.5, the 30-day average shall be the average of all valid hours of CO emissions data for any 30 successive operating days. The average shall exclude data from periods of startup and shutdown.

c. For the SO_2 emission limit required in Condition 2.1, the 30-day average shall be the average of all valid hours of SO_2 emissions data for any 30 successive operating days. The average shall exclude data from periods of startup and shutdown.

After the first 30-day average, a new 30-day rolling average shall be calculated after each operating day. For the purpose of this Permit, an operating day is a 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time. It is not necessary for the fuel to be combusted continuously for the entire 24-hour period. These records (including calculations) shall be maintained as part of the monthly record suitable for inspection or submittal.

7.11 The Permittee shall record and maintain records of the amounts of each fuel, including fuel type, combusted during each day in the Biomass Cogeneration Boiler (Source Code: B01). The Permittee shall use these records to demonstrate compliance with Condition 2.29. These records (including calculations) shall be maintained as part of the monthly record suitable for inspection or submittal.
[Avoidance of 40 CFR 52.21 and 391-3-1-.02(6)(b)1]

7.12 The Permittee shall maintain the following records as they relate to the startup and shutdown of the Biomass Cogeneration Boiler (Source Code: B01):
[Avoidance of 40 CFR 52.21 and 391-3-1-.02(6)(b)1]

a. The number of startups per day; the hours attributed to the startup, and the hours attributed to shutdown. If Source B01 was not in operation on any given day, the records shall so note.

b. Identify times of startup of the pollution control systems – SNCR-1, BH-1, and SI-1.

7.13 The Permittee shall verify that each shipment of biomass fuel received for combustion in the Biomass Cogeneration Boiler complies with the requirements of Condition 2.28 through purchasing agreements that require all biomass suppliers to certify that all receipts meet the applicable biomass definition. Verification shall consist of a certification statement included on the shipping document accompanying each load. The Permittee shall retain records on site for a period of at least five years in a format suitable for inspection.
[Avoidance of 40 CFR 52.21 and 391-3-1-.02(6)(b)1]

7.14 The Permittee shall submit a written report containing the following information for each quarterly period ending March 31, June 30, September 30, and December 31 of each year. All reports shall be postmarked by the 60th day following the end of each reporting period, (June 30, September 30, December 31, and March 31, respectively). Reporting required by this condition shall begin at the end of the quarter in which initial startup is completed.
[Avoidance of 40 CFR 52.21 and 391-3-1-.02(6)(b)1]

a. The 30-day rolling average NOx emission rate in lb/MMBtu from the Biomass Cogeneration Boiler (Source Code: B01), for each 30-day period during the quarterly reporting period.

b. The 30-day rolling average CO emission rate in lb/MMBtu from the Biomass Cogeneration Boiler (Source Code: B01), for each 30-day period during the quarterly reporting period.

c. The 30-day rolling average SO_2 emission rate in lb/MMBtu from the Biomass Cogeneration Boiler (Source Code: B01), for each 30-day period during the quarterly reporting period.

d. The type (i.e., biomass or natural gas) and amount of fuel burned in the Biomass Cogeneration Boiler (Source Code: B01) during the reporting period.

40 CFR 63 Subpart DDDDD

7.15 The Permittee shall complete tune-ups as specified in 40 CFR 63.7540(a)(12).
[40 CFR 63.7510(g)]

Notification of Intent

7.16 The Permittee shall submit a Notification of Intent to conduct a performance test at least 60 days before the performance test is scheduled to begin.
[40 CFR 63.7545(d)]

Recordkeeping Requirements

7.17 The Permittee shall maintain the following records as related to the Biomass Cogeneration Boiler (Source Code: B01) and 40 CFR 63 Subpart DDDDD:

a. A copy of each notification and report submitted by the Permittee to comply with 40 CFR 63 Subpart DDDDD, including all documentation supporting any Initial Notification or Notification of Compliance Status annual compliance reports.
[40 CFR 63.10(b)(2)(xiv) and 40 CFR 63.7555(a)(1)]

b. Records of performance tests, fuel analyses, or other compliance demonstrations and performance evaluations.

c. For each CEMS, COMS, and continuous monitoring system the Permittee must keep records according to 40 CFR 63.7555(b)(1) through 40 CFR 63.7555(b)(5).
[40 CFR 63.7555(b)]

d. Records required in Table 8 of 40 CFR 63 Subpart DDDDD, including records of all monitoring data and calculated averages for applicable operating limits, such as opacity, pressure drop, pH, and operating load, to show continuous compliance with each emission limit and operating limit.
[40 CFR 63.7555(c)]

e. Applicable records in 40 CFR 63.7555(d)(2) through 40 CFR 63.7555(d)(11).
[40 CFR 63.7555(d)]

f. Monthly fuel use, including the type(s) of fuel and amount(s) used.
[40 CFR 63.7555(d)(1)]

g. Records of the calendar date, time, occurrence and duration of each startup and shutdown.
[40 CFR 63.7555(d)(9)]

h. Records of the types(s) and amount(s) of fuels used during each startup and shutdown.
[40 CFR 63.7555(d)(10)]

i. The Permittee shall maintain the records in a form suitable and readily available for expeditious review.
[40 CFR 63.10(b)(1) and 40 CFR 63.7560(a)]

j. The Permittee shall maintain each record for five years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.
[40 CFR 63.10(b)(1) and 40 CFR 63.7560(b)]

k. The Permittee must keep each record on site, or they must be accessible from on site, for at least two years after the date of each occurrence, measurement, maintenance, corrective action, report, or record. The Permittee can keep the records off site for the remaining three years.
[40 CFR 63.10(b)(1) and 40 CFR 63.7560(c)]

7.18 The Permittee shall retain the following operating records, using the hour meters required by Permit Condition 2.24 of the permit, for the Emergency Engine (EE) and Fire Water Pump Engine (FPE) listed in Table 1 and Table 2:
[391-3-1-.02(6)(b)1]

a. Monthly operating hours for the Emergency Engine (EE) and Fire Water Pump Engine (FPE) to include reason for operation.

7.19 The Permittee shall maintain the following records for each Method 9 performance test conducted in accordance with Condition 6.2.h. [Does not apply if the Permittee elects to install a PM CEMS.]
[Subpart Da, 40 CFR 60.52Da(b)(1)]

a. Dates and time intervals of all opacity observation periods.

b. Name, affiliation, and copy of current visible emission reading certification for each visible emission observer participating in the performance test.

c. Copies of all visible emission observer opacity field data sheets.

7.20 If the Permittee elects to install a PM CPMS, the Permittee shall maintain the following PM CPMS records:
[Subpart DDDDD – 40 CFR 63.7555(b) and 40 CFR 60.49Da(t) which references 40 CFR 63.10032]

a. Records described in 40 CFR 63.10(b)(2)(vii) through (xi).

b. Previous (i.e., superseded) versions of the performance evaluation plan as required in 40 CFR 63.8(d)(3).

c. Records of the date and time that each deviation started and stopped, and whether the deviation occurred during a period of startup, shutdown, or malfunction or during another period.

d. Records required in Item 2, Table 7 of 40 CFR 63, Subpart UUUUU, including records of all monitoring data and calculated averages for applicable PM CPMS operating limits to show continuous compliance with each emission limit and operating limit that applies to the Permittee.

e. Records of the occurrence and duration of each malfunction of the Biomass Cogeneration Boiler (Source Code: B01) or the air pollution control and monitoring equipment.

f. Records of actions taken during periods of malfunction to minimize emissions in accordance with 40 CFR 63.10000(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

7.21 For any deviation of the 30-boiler operating day rolling PM CPMS average value from the established operating parameter limit, the Permittee must:
[Subpart DDDDD – 40 CFR 63.7540(a)(18)(ii)]

a. Within 48 hours of the deviation, visually inspect the Baghouse (Source Code: BH-1);

b. If inspection of the Baghouse (Source Code: BH-1) identifies the cause of the deviation, take corrective action as soon as possible and return the PM CPMS measurement to within the established value; and

c. Within 30 days of the deviation or at the time of the annual compliance test, whichever comes first, conduct a PM emissions compliance test to determine compliance with the PM emissions limit and to verify or re-establish the CPMS operating limit. The Permittee is not required to conduct additional testing for any deviations that occur between the time of the original deviation and the PM emissions compliance test required under this condition.

7.22 If the Permittee elects to install a PM CPMS, the Permittee shall calculate PM emissions discharged to the atmosphere from the Biomass Cogeneration Boiler (Source Code: B01) by multiplying the average hourly PM output concentration (measured according to the provisions of Condition 5.14), by the average hourly flow rate (measured according to Condition 5.10) and dividing by the average hourly gross energy output (measured according to the provisions of Condition 5.11) or the average hourly net energy output, as applicable.
[Subpart Da - 40 CFR 60.48Da(n)]

7.23 The Permittee shall submit written notification of the date RPF's No. 3 Power Boiler (Source Code: PB03) is decommissioned within 15 days after such date. This notification shall include the date the shakedown period for the Biomass Cogeneration Boiler (Source Code: B01) was completed to demonstrate compliance with Condition 2.31.
[Avoidance of 40 CFR 52.21(j)]

8. Special Conditions

8.1 At any time that the Division determines that additional control of emissions from the facility may reasonably be needed to provide for the continued protection of public health, safety and welfare, the Division reserves the right to amend the provisions of this Permit pursuant to the Division's authority as established in the Georgia Air Quality Act and the rules adopted pursuant to that Act.

8.2 The Permittee shall calculate and pay an annual Permit fee to the Division. The amount of the fee shall be determined each year in accordance with the "Procedures for Calculating Air Permit Application & Annual Permit Fees."

8.3 The Permittee shall submit a completed Part 70 Operating Permit application to the Division in the approved format within 12 months after startup of operations of equipment specified in Application 29489.