



PROJECT REPORT

THE PROCTER & GAMBLE PAPER PRODUCTS COMPANY CONSTRUCTION AND OPERATING PERMIT APPLICATION

VOLUME I

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1. PROJECT SUMMARY

Sterling Energy Assets (Sterling) plans to construct a Biomass Cogeneration Boiler at the Procter and Gamble Paper Products Company (P&GPP), located in Albany, Georgia. Approximately half of the steam to be produced in the approximate 1,037 MMBtu/hr circulating fluid bed (CFB) Biomass Cogeneration Boiler will be used to generate power for the electrical grid. The other half will be supplied to the adjacent P&GPP operations to replace steam currently produced by an existing, permitted 216 MMBtu/hr heat input biomass boiler (ID No. B002) that will be decommissioned following the shakedown period associated with the cogeneration plant and will also be used to replace process heat generated from natural gas combustion in existing permitting duct burners as a backup. There will be no physical changes to the production equipment that can increase production capacity or utilization and the use of steam for heating will only maintain existing production capacity. P&GPP will continue to maintain the capacity to use the natural gas duct burners and backup natural gas boiler for process heating during periods of downtime of the Biomass Cogeneration Boiler.

The proposed modification to the Albany facility will consist of the addition of a 1,037 MMBtu/hr Biomass Cogeneration Boiler and ancillary sources including a biomass storage pile, sorbent silo, flyash storage silo, and cooling tower. Construction of the facility is anticipated to begin in late 2013.

1.1. REGULATORY APPLICABILITY

The existing P&GPP facility is currently classified as major source under the PSD permitting program. The proposed project triggers PSD review with net emission increases from the project exceeding the PSD Significant Emission Rates (SERs) for nitrogen oxides (NO_x), particulate matter (PM, also called total suspended particulate [TSP]), particulate matter less than 10 or 2.5 microns in aerodynamic diameter (PM₁₀ and PM_{2.5}), sulfur dioxide (SO₂), and volatile organic compounds (VOC). For each pollutant exceeding the PSD SER, application of Best Available Control Technology (BACT) to reduce emissions is required. Air quality modeling analyses are also required for criteria pollutants subject to PSD review, as well as modeling for certain toxic air pollutants (TAPs) in accordance with relevant Georgia Natural Resources Environmental Protection Division's (GA EPD's) regulations. The Biomass Cogeneration Boiler will be subject to New Source Performance Standards (NSPS) and National Emissions Standards for Hazardous Air Pollutants (NESHAP).

In addition to the major regulatory requirements highlighted above, this permitting action will trigger several other state requirements addressed by this application, including a revision to P&GPP's existing Title V operating permit.

1.2. BACT DETERMINATION

P&GPP performed BACT analyses for each of the PSD-regulated pollutants and emission units subject to PSD review generally following the "top-down" approach suggested by U.S. EPA. The top-down process begins by ranking all potentially relevant control technologies in descending order of control effectiveness. The most stringent or "top" control option is BACT unless the applicant demonstrates, and the permitting authority in its informed opinion agrees, that energy, environmental, and/or economic impacts justify the conclusion that the most stringent control option does not meet the definition of BACT. Where the top option is not determined to be BACT,

the next most stringent alternative is evaluated in the same manner. This process continues until BACT is determined. BACT evaluations are provided in Section 5 of this report.

1.3. AIR QUALITY ANALYSIS

The air dispersion modeling and other air quality analyses required under PSD are provided in Volume II of this report. Air dispersion modeling required pursuant to the GA EPD's toxics program will be provided under separate cover. Modeling analyses are conducted in accordance with the approved modeling protocol¹, U.S. EPA's *Guideline on Air Quality Models*, 40 CFR Part 51, Appendix W (Revised, November 9, 2005), the U.S. EPA's *AERMOD Implementation Guide*², and the Georgia EPD's *Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions* (June 21, 1998).³

The modeling analyses demonstrate that the project will not cause or contribute to an exceedance of any National Ambient Air Quality Standards (NAAQS) or Class II PSD Increment requirements. An additional impacts analysis is also included in Volume II.

1.4. APPLICATION ORGANIZATION

The following information is included as part of this application submittal:

- Section 1 includes the application summary;
- Section 2 provides a description of the proposed project;
- Section 3 discusses the emissions calculation methodologies and presents the facility-wide potential emissions;
- Section 4 details the regulatory applicability analysis;
- Section 5 presents the BACT analysis;
- Appendix A contains the construction permit application forms;
- Appendix B presents the detailed emission calculations for the new emission units
- Appendix C presents the actual emission calculations for the existing biomass boiler that is being decommissioned, and
- Appendix D contains BACT supporting information.

¹ Letter from Jon Hill (Trinity Consultants) to Yan Huang (Georgia EPD), May 3, 2013. Approval of protocol provided in letter from Mr. James Boylan (Georgia EPD) to Jon Hill, May 17, 2013.

² www.epa.gov/scram001/7thconf/aermod/aermod_implmtn_guide_19March2009.pdf

³ www.georgiaair.org/airpermit/downloads/otherforms/infodocs/toxguide.pdf

2. FACILITY DESCRIPTION

This section describes the current plant operations and proposed modification to the Albany facility.

2.1. SITE DESCRIPTION

The Albany facility is located in the northeast portion of Dougherty County in Georgia along Liberty Expressway Southeast (State Route 19) approximately 5 miles southeast of downtown Albany. The facility primarily manufactures sanitary paper products including paper towels and tissue paper. An area diagram including site layout are provided in Volume II of this report. P&GPP operates Boiler 2 (B002), a 216 MMBtu/hr biomass-fired unit, which supplies process steam for papermaking operation. Process heat is also provided by a number of natural gas/No. 2 oil-fired duct burners providing direct contact heating to the papermaking operations.

2.2. PROPOSED OPERATIONS

Sterling Energy Assets (Sterling) plans to construct a Biomass Cogeneration Boiler at P&GPP's facility to replace process heat generated by existing Boiler No. 2 and a portion of the existing duct burners, as well as generate power for the electrical grid. Approximately half of the steam to be produced in the approximate 1,037 MMBtu/hr circulating fluid bed (CFB) Biomass Cogeneration Boiler will be used to generate power for the electrical grid, with the remainder used to supply steam to the P&GPP operations. Boiler No. 2 will be decommissioned following the shakedown period associated with the cogeneration plant. P&GPP will be operating the cogeneration plant and, accordingly, P&GPP is responsible for permitting of the facility.

Figure 2-1 presents a layout of the proposed biomass P&GPP facility after the proposed modifications have been completed. Biomass (i.e., pre-chipped wood, bark, wood waste, peanut hulls, etc.) will be delivered to the site via trucks utilizing P&GPP's private paved road. The facility will be designed to accept 100% chipped biomass.

Raw material trucks will transfer biomass at a truck tipping station into a hopper that is enclosed on the sides to effectively shield the dumping operation from the effects of wind. To eliminate emissions from the dumping process itself, a water spray system will be employed over the top of the chip receiving bin. From the bin, biomass will be transferred using a series of enclosed conveyors to the storage pile. It should be noted that prior to transfer to storage, a small fraction of oversized biomass will be screened and diverted through an enclosed electric hogger for size reduction.

Biomass will be transferred to the biomass pile using a telescoping rubber chute conveyor that is equipped with water sprays at the outlet. The drop distance to the pile will be minimized by maintaining the rubber chutes near the interface with the pile such that emissions from the transfer are negligible. Biomass from the pile will be conveyed to the Biomass Cogeneration Boiler using a subsurface underground reclaim chain that feeds the biomass to the enclosed conveyors feeding the proposed Biomass Cogeneration Boiler.

Bottom and flyash handling are discussed later in this section.

The proposed facility's air emissions units will be added as a result of this project:

- > Biomass Cogeneration Boiler
- > Biomass storage pile
- > Sorbent silo
- > Flyash storage silo
- > Cooling tower

The following existing P&GPP air emissions units will be removed as a result of this project:

- > Existing 216 MMBtu/hr Biomass Stoker Boiler
- > Biomass Storage Pile

A process flow diagram for the proposed facility operations is provided in Figure 2-1. Air emission units and certain ancillary operations with no emissions are discussed in the following subsections.

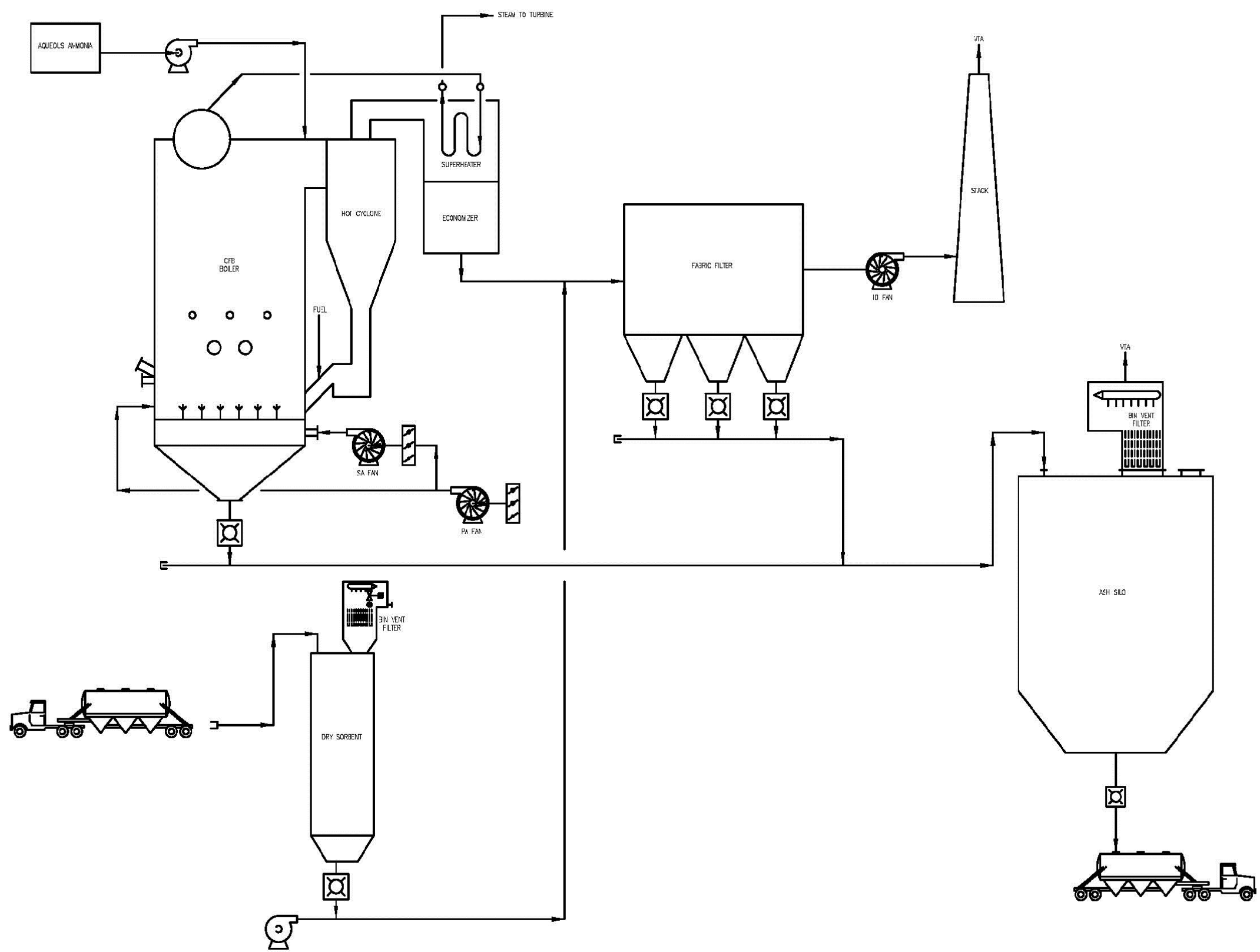
2.2.1. Circulating Fluidized Bed Biomass Cogeneration Boiler

The proposed circulating fluidized bed (CFB) Biomass Cogeneration Boiler will fire biomass as the primary fuel and have a heat input of 1,037 MMBtu/hr, potentially operating up to 8,760 hours per year.

The boiler will employ multiple pollution control devices, as shown in Table 1-1. Filterable particulate matter will be controlled by a baghouse (also known as a fabric filter). NO_x will be reduced by a selective non-catalytic reduction (SNCR) system in addition to the overfire air system (OFA) inherent in fluidized bed combustor design. SO₂ and acid gas emissions will be controlled by duct sorbent injection (DSI) using either trona or sodium bicarbonate into the flue gas stream. Mercury (Hg) will be controlled by activated carbon injection unless stack testing indicates that use of activated carbon is unnecessary to meet applicable emissions standards. Good combustion practices will be employed to minimize CO and organic emissions.

Up to two cold startups of the boiler per year will be accomplished using natural gas. A startup curve depicting fuel firing versus time is provided in Figure 2-3. Initially natural gas is fired at a heat input rate of 200 MMBtu/hr. The baghouse is bypassed until Hour 6 to prevent condensation in the baghouse. At Hour 6, biomass begins to be introduced and the baghouse and DSI are engaged at this time. At approximately Hour 7 when biomass firing reaches approximately 475 MMBtu/hr and the combined heat input reaches approximately 65%, the temperature profile within the boiler is within the proper range to engage the SNCR. It should be noted that once the SNCR system is engaged and only biomass is being fired, the SNCR system can remain engaged to approximately 40% load; however, operation at such low loads is not anticipated during normal operations.

FIGURE 2-1. PROCESS FLOW DIAGRAM



2.2.2. Raw Material Receiving and Storage

The raw material handling and storage equipment will provide the necessary functions to receive, process, store, and convey biomass fuel to the Biomass Cogeneration Boiler. Except for fugitive wind erosion emissions from the biomass storage pile, the biomass fuel handling system is designed to abate fugitive dust emissions to negligible levels.

2.2.2.1. Biomass Receiving Operations & Processing

Pre-chipped biomass will be delivered to the site via trucks utilizing P&GPP's private paved road (it should be noted that truck roads in the cogeneration plant area are all paved). Raw material trucks will transfer biomass at a truck tipping station into a hopper that is enclosed on the sides to effectively shield the dumping operation from the effects of wind. To eliminate emissions from the dumping process itself, a water spray system will be employed over the top of the chip receiving bin. From the bin, chipped biomass will be transferred using a series of enclosed conveyors to the storage pile.

It should be noted that prior to transfer to storage, a small fraction, very conservatively estimated at approximately 25 percent, of oversized biomass will be screened and diverted through an enclosed electric hogger for size reduction.

2.2.2.2. Biomass Storage Pile

Biomass will be transferred to the biomass storage pile using a telescoping rubber chute conveyor that is equipped with water sprays at the outlet. The drop distance to the pile will be minimized by maintaining the rubber chutes near the interface with the pile such that emissions from the transfer are negligible. Chipped biomass from the pile will be conveyed to the Biomass Cogeneration Boiler using a subsurface underground reclaim chain that feeds the biomass to the enclosed conveyors feeding the proposed Biomass Cogeneration Boiler.

2.2.3. Sorbent Storage Silo

A sorbent storage silo equipped with fabric filtration system will store the alkaline sorbent (trona or sodium bicarbonate). The sorbent will be delivered to the site by trucks and pneumatically conveyed to a storage silo. The sorbent is pneumatically conveyed into the Biomass Cogeneration Boiler using lances in the flue gas ductwork upstream of the fabric filter. The injection system is completely enclosed. At this time, it is not envisioned that additional milling of the sorbent will be required prior to injection; however, if such a system is installed, it will be completely enclosed with no emissions to the atmosphere.

2.2.4. Bottom Ash Handling and Flyash Storage Silo

Bottom ash is thoroughly wetted as it is drawn from the Biomass Cogeneration Boiler and conveyed to a storage bin with no emissions. Bottom ash is conveyed by pugmill into open trucks that remove the ash from the site for disposal. There are no dust emissions from minor drop from the pugmill into the truck due to water sprays, residual moisture content of the ash, and its propensity to remain clumped (again due to the moisture).

A flyash silo equipped with fabric filtration system will store flyash collected from the cogeneration plant particulate matter control systems (i.e., multiclone and baghouse). Flyash will be unloaded

into trucks for off-site use. An access bay will be provided beneath the silo to allow truck access. Ash loadout will occur through a telescoping discharge chute equipped with include a vacuum annulus and water sprays near the outlet of the chute. The combined effect of the wind break, telescoping chute, vacuum annulus and water sprays eliminates dust emissions. It should be noted that after filling, the truck will be covered with a tarp prior to leaving the loadout area to eliminate fugitive dust emissions.

2.2.5. Cooling Tower

Steam exiting the steam turbine will be condensed via indirect heat transfer using a mechanical draft, counterflow wet cooling tower. Cooling tower drift will be minimized to 0.001% of the design recirculation rate.

2.3. INTERACTION WITH EXISTING P&GPP PROCESSES AND SHUTDOWN OF BOILER NO. 2

As noted earlier, approximately 50 percent of the steam generated by the process will typically be supplied to P&GPP in support of papermaking operations at the plant. Following the shakedown period of the Biomass Cogeneration Boiler, P&GPP will decommission Boiler No. 2, Emission Unit ID No. B002. P&GPP is requesting a federally enforceable limit requiring permanent shutdown of existing biomass boiler (ID No. B002) immediately following completion of the shakedown period for the Biomass Cogeneration Boiler. This is discussed in detail in Section 4.11. P&GPP is relying upon the emissions offsets for nitrogen oxides (NO_x) associated with shutdown of the boiler in the modeling demonstration for this project. Papermaking operations associated with steam currently being produced by Boiler No. 2 will not be impacted (no increase in production rate) as a result of this project.

Some of the additional steam being produced will be used for heating in existing papermaking operations that currently receive direct heat from existing natural gas burners. Ductwork currently used for providing heat from the duct burners will be modified in order to install steam heating coils to allow indirect heat transfer for existing process heating needs. The current process heating system heats air to specific setpoint temperatures that will not change as a result of this project. Accordingly, the production rate of the process will not increase as a result of this project. It should be noted that the existing duct burners will remain in place and be used during periods of Biomass Cogeneration Boiler downtime and for temperature boost (a.k.a., “trim”) to setpoint temperature.

3. EMISSIONS CALCULATIONS

This section addresses the methodologies used to quantify the emissions increases associated with the proposed facility. Detailed calculations of both criteria and non-criteria pollutants are located in Appendix B.

3.1. PSD-REGULATED POLLUTANT EMISSIONS FOR NEW EMISSION SOURCES

Sources of criteria pollutant emissions include fuel combustion, material handling and storage, cooling towers, and fugitive dust. The sources and calculation methodologies are discussed in the following sections. Note that annual emissions are based on 8,760 hours per year of operation unless otherwise noted.

3.1.1. Biomass Cogeneration Boiler

Combustion in the circulating fluidized bed boiler will result in emissions of CO, NO_x, PM (including speciated fraction), SO₂, and VOC. The PSD-regulated uncontrolled and controlled emissions are based on proposed limits and/or vendor emission factors taking into account proposed control devices: SNCR, baghouse, dry sorbent injection, and activated carbon injection. The expected blend of biomass fuels that were used to develop flow rates and uncontrolled emissions will be the same as is used in the existing Boiler No. 2. The unit is requesting to fire biomass during normal operation (e.g., bark, wood waste, peanut and pecan hulls) and natural gas during startup.

Expected short-term (lb/hr) emissions from maximum operation of the Biomass Cogeneration Boiler were estimated using the boiler's short-term heat input of 1,037 MMBtu/hr and lb/MMBtu proposed BACT limits (discussed in Section 5 of this report) and/or expected vendor guarantees. However, these values do not account for variability at the shorter averaging periods used for modeling. Volume II (modeling) discusses short-term emissions potentially suitable for permit limits that consider the variability at shorter averaging periods than the 30-day average used for BACT.

Expected short-term emissions from startup scenarios were also considered. Startup will require usage of natural gas to heat the boiler bed while shutdown will not require any auxiliary fuel. As previously noted, P&GPP is will combust natural gas at 200 MMBtu/hr for startup.

Expected maximum short-term emissions were calculated from taking the worst case short term emission estimates from startup operations and normal operations. Emission estimates are based on worst-case vendor estimates, AP-42 Section 1.4 External Combustion Sources- Natural Gas Combustion, and AP-42 Section 1.6 External Combustion Sources- Wood Residue Combustion in Boilers. Appendix B illustrates the maximum short-term emissions for criteria pollutants in normal operations, i.e., biomass combustion. Long-term emission estimates were calculated by multiplying the worst-case short term emission factor (lb/hr) by 8,760 hours per year.

The maximum expected short-term emissions represented in the permit application forms were selected as the maximum of the normal and startup/shutdown operations. Annual emissions were based on the worst-case scenario: normal operation firing biomass for the entire year. Detailed calculations are presented in Appendix B. Note PM₁₀ and PM_{2.5} is assumed to be equal to PM as the Biomass Cogeneration Boiler vendor did not provide separate emissions data.

3.1.2. Biomass Receiving and Storage

The biomass storage system is a source of particulate emissions and/or volatile organic compounds (VOC). Partial or complete enclosures of emissions sources (where practicable) will also be utilized to minimize fugitive PM emissions.

3.1.2.1. Biomass Storage Piles

Fugitive particulate emissions from the uncovered storage pile (SP01) were quantified. Emission factors were developed based on surface area of the piles in accordance with U.S. EPA guidance for storage pile fugitive emissions.⁴ These factors provide estimates of PM emissions due to wind erosion at the surface of each storage pile based on the annual frequency of high wind speeds (> 12 mph). Detailed calculations are also included in Appendix B. Note that PM₁₀ is assumed to equal 50% of PM₅, while PM_{2.5} is assumed to be 7.5% of PM.⁶

In addition to particulate matter emission, volatile organic compounds are also emitted from the storage pile. Emission factors were obtained from National Council for Air and Stream Improvement (NCASI) document provided by SC DHEC for the calculation of fugitive VOC emissions from woody biomass storage piles. Emission factors ranged from 1.6 to 3.6 lb C/acre-day. P&GPP chose to employ the maximum emission factor for purposes of conservatism. Emission factors are given in terms of pounds of carbon per surface area of the pile. The VOC makeup of woody biomass is primarily composed of terpenes (C₅H₈)_n [where n = 2, 3, or 4 typically]. To convert from carbon to the equivalent weight in VOC, the assumption was that alpha-pinene (AP) would be the representative VOC (molecular weight = 136.2 lb/lb-mol). The following equation shows the conversion: ton VOC/year = ton C/year * (136.2 lb/mol AP / 12 lb/mol C) * (1 mol AP / 10 mol C). Detailed calculations are included in Appendix B.

3.1.2.2. Biomass Processing

VOC emissions from the hogger operation are based on 25 percent of the biomass processed for the proposed Biomass Cogeneration Boiler. Emission factors were obtained from available emission factors for chippers in AP-42 Section 10.6.3, Table 7 and Section 10.6.4, Tables 7 and 9. Emission factors for THC and Methanol are the same across all three tables. The THC/VOC makeup of woody biomass is primarily composed of terpenes (C₅H₈)_n [where n = 2, 3, or 4 typically] but to convert from carbon to the equivalent weight in THC/VOC, the assumption was that alpha-pinene (AP) would be the representative THC/VOC (molecular weight = 136.2 lb/lb-mol). Detailed emission calculations are presented in Appendix B.

3.1.3. Sorbent and Flyash Sorbent Silos

The sorbent and flyash storage silos are a source of PM emissions. Particulate emissions from the sorbent and ash are based on air flow rate for each of the silos and a filter outlet particulate matter grain loading factor of 0.005 gr/ft³ (the proposed BACT limit). The sorbent storage silo has an air flow rate of 200 acfm, while the flyash storage silo has an air flow rate of 1,000 acfm. It was

⁴ U.S. EPA *Control of Open Fugitive Dust Sources*, Research Triangle Park, North Carolina, EPA-450/3-88-008. September 1988.

⁵ U.S. EPA *Control of Open Fugitive Dust Sources*, Research Triangle Park, North Carolina, EPA-450/3-88-008. September 1988.

⁶ U.S. EPA *Background Document for Revisions to Fine Fraction Ratios Used for AP-42 Fugitive Dust Emission Factors*. November 2006. <http://www.epa.gov/ttn/chief/ap42/ch13/bgdocs/b13s02.pdf>.

conservatively assumed that the sorbent silo will operate 300 hours per year based on 300 trucks unloading each year and 1 hour of unloading time. The ash storage silo it is conservatively assumed continuous operation of 8,760 hours per year. Storage silo emission calculations are presented in Appendix B.

Note that for conservatism, PM_{2.5} and PM₁₀ emissions were assumed to be equal to PM.

3.1.4. Cooling Towers

Cooling towers produce a small amount of PM emissions when water droplets evaporate, leaving the dissolved solids in the water as PM. Emissions from the cooling towers are based on 0.0005% drift loss (the proposed BACT limit), the design circulation rate, and total dissolved solids (TDS) design for the cooling tower.⁷ Cooling tower calculations are included in Appendix B.

3.2. PSD-REGULATED POLLUTANT EMISSIONS FOR BASELINE ACTUAL EMISSIONS

As noted earlier, following the shakedown period of the Biomass Cogeneration Boiler, P&GPP will decommission Boiler No. 2, Emission Unit ID No. B002 and the existing storage pile. Decreases associated with the decommission of Boiler No. 2 and the storage pile has not been taken into account in the PSD netting calculations as discussed in Section 4.2. However, decreases from NO₂, are taken into account for modeling purposes as discussed in Volume II. These emission units are sources of criteria pollutant emissions. The sources and calculation methodologies are discussed in the following sections.

3.2.1. Boiler No. 2 (B002)

Combustion in the existing boiler will result in emissions of CO, NO_x, PM (including speciated fraction), SO₂, and VOC. The baseline emissions are based on calendar year emission inventories for 2011 and 2012. All pollutant emissions except PM are based on AP-42 Section 1.6 External Combustion Sources- Wood Residue Combustion default emission factors when biomass was combusted and AP-42 Section 1.3 External Combustion Sources- Fuel Oil Combustion for fuel oil combustion. February 2009 stack test for filterable particulate matter was used to calculate PM emission rates in the 2011 inventory and a December 2011 stack test was used for PM emissions for the 2012 inventory as shown in Appendix C.

3.2.2. Biomass Storage Piles

Fugitive particulate emissions from the existing uncovered storage pile were quantified using the same methodology as the new storage pile. Emission factors were developed based on surface area of the pile in accordance with U.S. EPA guidance for storage pile fugitive emissions assuming a cone storage pile shape for comparison purposes to the new pile.⁸ These factors provide estimates of PM emissions due to wind erosion at the surface of each storage pile based on the annual frequency of

⁷ U.S. EPA AP-42, Section 13.4, *Wet Cooling Towers and Effects of Pathogenic and Toxic Material Transport Via Cooling Device Drift - Vol. 1 Technical Report* EPA 600 7-79-251a, November 1979.

⁸ U.S. EPA *Control of Open Fugitive Dust Sources*, Research Triangle Park, North Carolina, EPA-450/3-88-008. September 1988.

high wind speeds (> 12 mph). Detailed calculations are also included in Appendix B. Note that PM₁₀ is assumed to equal 50% of PM₉, while PM_{2.5} is assumed to be 7.5% of PM.¹⁰

3.3. HAP/TAP EMISSIONS

HAP emissions are regulated by U.S. EPA under Title III of the Clean Air Act Amendments of 1990 and comprise 187 compounds. A Toxic Air Pollutant (TAP) is defined by Georgia EPD as any substance that may have an adverse effect on public health, excluding pollutants covered by a State or Federal ambient air quality standard. Thus, HAP is a subset of TAP. Based on guidance received from the GA EPD during the PSD preapplication meeting, the only TAPs requiring evaluation in this permit application are those evaluated in the permit application submitted for the Green Energy Resource Center.

3.3.1. Biomass Cogeneration Boiler Combustion

The facility will utilize a single modern, fluidized bed boiler combusting biomass. The Biomass Cogeneration Boiler will be equipped with a fabric filter and will utilize duct sorbent injection to minimize particulate (filterable and condensable), and acid gas emissions. Using these control techniques coupled with the fluidized bed design, the organic, particulate, and acid gas emissions will be minimized.

Acid gas (HCl, HF) emission factors were taken from boiler vendor estimates for HCl, and HF was assumed to be 50% of the HCl emission factor. A conservative HCl control efficiency was also applied from the duct sorbent injection of 88.77%. For particulate, HAP, and TAP emissions P&GPP utilized the AP-42 Section 1.6 default metal emission factors.

For the short term (lb/hr) organic HAP and TAP biomass factors, P&GPP compared default AP-42 Section 1.6 default emission factors for the combustion of wood based on a heat input of 1,037 MMBtu/hr during normal operations versus AP-42 Section 1.4 combustion of Natural Gas for combustion of natural gas based on a heat input of 200 MMBtu/hr during startup. For annual biomass emissions, potential emissions were calculated using the maximum short-term emission rate and the annual heat input of 1,037MMBtu/hr and 8,760 hours per year. The maximum short-term emission rates for most pollutants are shown in Appendix B to be from normal operations combusting biomass.

⁹ U.S. EPA *Control of Open Fugitive Dust Sources*, Research Triangle Park, North Carolina, EPA-450/3-88-008. September 1988.

¹⁰ U.S. EPA *Background Document for Revisions to Fine Fraction Ratios Used for AP-42 Fugitive Dust Emission Factors*. November 2006. <http://www.epa.gov/ttn/chief/ap42/ch13/bgdocs/b13s02.pdf>.

4. REGULATORY REQUIREMENTS

The proposed facility will be subject to certain federal and state air quality regulations. This section of the application summarizes the air permitting requirements and the key air quality regulations that will apply to the proposed facility. Specifically, applicability to New Source Review (NSR), New Source Performance Standards (NSPS), pollutant- and category-specific National Emission Standards for Hazardous Air Pollutants (NESHAP), Compliance Assurance Monitoring (CAM), Risk Management Plan (RMP) regulations, Title V operating permit regulations, Acid Rain Program (ARP), stratospheric ozone protection, and Georgia State Implementation Plan (SIP) regulations are addressed.

4.1. STATIONARY SOURCE DEFINITION

Air quality permitting for NSR (and Title V) is only applicable to stationary sources. *Stationary source* is defined in Title III of the Clean Air Act (General Provisions) as:

The term “stationary source” means generally any source of an air pollutant except those emissions resulting directly from an internal combustion engine for transportation purposes or from a nonroad engine or nonroad vehicle as defined in section 216.

[Clean Air Act, Section 302(z)]

Thus, nonroad engines as defined under Title II of the Clean Air Act (Section 216) are not stationary sources and their emissions are not considered under either NSR or Title V.

Most of the sources at the P&G facility are stationary sources (e.g., the Biomass Cogeneration Boiler, silos, cooling towers). Diesel engines in the biomass delivery trucks are for transportation purposes and are excluded from the definition of a stationary source.

It should be noted that Sterling will be the owner of the Biomass Cogeneration facility; however, P&GPP controls day-to-day operation of the facility. Since approximately one half of the steam output will be used for heating of P&GPP's process and the cogeneration plant is located adjacent to P&GPP properties, the cogeneration plant is considered part of P&GPP's operations with respect to both PSD and Title V applicability.

4.2. PSD APPLICABILITY

The NSR permitting program generally requires a stationary source to obtain a permit and undertake other obligations prior to construction of any project at an industrial facility if the proposed project results in the potential to emit air pollution in excess of certain threshold levels. The NSR program is comprised of two elements: nonattainment NSR (NNSR) and Prevention of Significant Deterioration (PSD). The NNSR program potentially applies to new construction or modifications that result in emission increases of a particular pollutant for which the area in which the facility is located is classified as “nonattainment” for that pollutant. The PSD program applies to project increases of those pollutants for which the area the facility is located in is classified as “attainment” or “unclassifiable”. The Albany facility is located in Dougherty County, which has been designated by the U.S. EPA as “attainment” or “unclassifiable” for all criteria pollutants. Therefore, the facility is potentially subject to PSD permitting requirements for all pollutants covered under this program.

The PSD program only regulates emissions from “major” stationary sources of regulated air pollutants. A stationary source is considered PSD major if potential emissions of any regulated pollutant exceed the major source thresholds. The PSD major source emission threshold is 250 tpy of a PSD-regulated pollutant unless the source belongs to one of 28 specifically defined industrial source categories for which the major source threshold is 100 tpy.¹¹ The P&GPP facility has fossil fuel-fired boilers with greater than 250 MMBtu/hr combined heat input and is therefore a category classified as major at the 100 tpy threshold. P&GPP has potential emissions of several PSD pollutants that exceed this level and is therefore an existing major stationary source under the PSD regulations.

As an existing major PSD source, the net emissions increases from the project have been compared to the respective PSD Significant Emission Rates (SERs) to determine whether PSD pollutants are subject to PSD review. A summary of PSD applicability for this project is shown in Table 4-1. Pollutants triggering PSD review for this project are: NO_x, SO₂, PM, PM₁₀, PM_{2.5}, VOC, and CO. P&GPP is not relying upon use of emission decreases associated with the Boiler No. 2 decommissioning and associated biomass pile shutdown for the PSD netting analysis; however, as discussed in Volume II, P&GPP is relying upon these decreases in the significant impact modeling evaluations.

4.3. NEW SOURCE PERFORMANCE STANDARDS

NSPS require new, modified, or reconstructed sources to control emissions to the level achievable by the best-demonstrated technology as specified in the applicable provisions. Moreover, any source subject to an NSPS is also subject to the general provisions of NSPS Subpart A, unless specifically excluded.

4.3.1. 40 CFR 60 Subpart A, General Provisions

All affected sources are subject to the general provisions of NSPS Subpart A unless specifically excluded by the source-specific NSPS. Subpart A requires initial notification and performance testing, recordkeeping, monitoring, provides reference methods, and mandates general control device requirements for all other subparts as applicable.

4.3.2. 40 CFR 60 Subpart Da, Electric Utility Steam Generating Units

NSPS Subpart Da, Standards of Performance for Electric Utility Steam Generating Units for which Construction is Commenced After September 18, 1978, applies to electric utility steam generating units with fossil fuel capacities greater than 250 MMBtu/hr (alone or in combination with any other fuel) for which construction, modification, or reconstruction commenced after September 18, 1978.¹² The maximum fossil fuel heat input of the natural gas-fired burners used for startup is only 200 and therefore NSPS Da is not applicable.

¹¹ 40 CFR 52.21(b)(1)(i)(a)

¹² 40 CFR 60.40a(a)

TABLE 4-1. PSD APPLICABILITY

Source Description	Permitted Source ID	CO (tpy)	NO _x (tpy)	PM (tpy)	PM-10 (tpy)	PM-2.5 (tpy)	SO ₂ (tpy)	VOC (tpy)	Pb (tpy)	CO _{2e} biomass deferral (tpy)
<i>Potential Emissions from New Units</i>										
Biomass Cogeneration Boiler	ES-B004	454.21	340.65	118.09	118.09	118.09	90.93	31.79	2.18E-01	20,588
Storage Pile	ES-SP1			0.28	0.14	0.02		2.15		
Sorbent Silo	ES-SS1			1.29E-03	1.29E-03	1.29E-03				
Flyash Silo	ES-FAS1			1.88E-01	1.88E-01	1.88E-01				
Hogger	ES-HOG							48.82		
Cooling Tower	ES-CT			0.22	0.12	0.0005				
Total Emissions		454.21	340.65	118.79	118.55	118.30	90.93	82.76	0.22	20,588
Project Emissions		454.21	340.65	118.79	118.55	118.30	90.93	82.76	0.22	20,588
SER		100	40	25	15	10	40	40	0.60	75,000
PSD Review Required		Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	No

4.3.3. 40 CFR 60 Subpart Db, Steam Generating Units > 100 MMBtu/hr

NSPS Subpart Db, *Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units*, provides standards of performance for steam generating units with capacities greater than 100 MMBtu/hr for which construction, modification, or reconstruction commenced after June 19, 1984.¹³ The proposed Biomass Cogeneration Boiler will be constructed after 1984, will have a maximum heat input capacity greater than 100 MMBtu/hr, and will generate steam. NSPS Subpart Db will apply to the proposed Biomass Cogeneration Boiler. The unit will also be subject to the more stringent requirements of the standard as it is being constructed post-February 2005.

Under NSPS Subpart Db, the particulate matter standard for a unit that combusts wood is 0.030 lb/MMBTU, and the opacity limit is 20 percent (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.¹⁴ The PM and opacity standards apply at all times, except during periods of startup, shutdown or malfunction.¹⁵ P&GPP is requesting a federally enforceable limit of annual heat input capacity which will ensure that the heat input from fossil fuel combustion is less than 10%. Inclusion of this limit in the permit will preclude a requirement to install a continuous emissions monitoring system for NO_x. The SO₂ standard of this subpart will not apply to the proposed Biomass Cogeneration Boiler because it will be firing fuels with a potential SO₂ emission rate of less than 0.32 lb/MMBtu (140 ng/J) via the usage of biomass and natural gas.¹⁶

Initial performance tests will be required for the Biomass Cogeneration Boiler using Method 5 for particulate matter and Method 9 for opacity.¹⁷ Further, in accordance with 40 CFR 60.48b(a), the affected facility must install, calibrate, maintain, and operate a continuous opacity monitor (COMS) or a bag leak detection system for measuring the opacity of emissions discharged to the atmosphere and record the output of the system.

Other record keeping and reporting requirements outlined in 40 CFR 60.49b will also apply to the boiler. Specifically, 40 CFR 60.49b(a) sets forth the initial reporting requirements of 40 CFR 60.7 for the notification of commencement of construction, notification of initial start-up, and the performance testing notifications and reports.

4.4. NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS

NESHAP, federal regulations found in Title 40 Parts 61 and 63 of the CFR, are emission standards for HAP and are primarily applicable to major sources of HAP (facilities that exceed the major source thresholds of 10 tpy of a single HAP and 25 tpy of any combination of HAP from stationary sources) or specifically designated area sources. NESHAP apply to sources in specifically regulated industrial source classifications (Clean Air Act Section 112(d)) or on a case-by-case basis (Clean Air Act Section 112(g)) for facilities not regulated as a specific industrial source type. Pollutant specific NESHAP may also be applicable. The P&GPP facility is a major source of HAP emissions as total HAP emissions exceed 25 tpy.

¹³ 40 CFR 60.40b(a)

¹⁴ 40 CFR 60.43b(f) and (h)(1)

¹⁵ 40 CFR 60.43b(g)

¹⁶ 40 CFR 60.42b(k)(2)

¹⁷ 40 CFR 60.46b(d)

4.4.1. 40 CFR 63 Subpart A, General Provisions

All affected sources are subject to the general provisions of Part 63 NESHAP Subpart A unless specifically excluded by the source-specific NESHAP. Subpart A requires initial notification and performance testing, recordkeeping, monitoring, provides reference methods, and mandates general control device requirements for all other subparts as applicable.

4.4.2. 40 CFR 63 Subpart Q, Cooling Towers

40 CFR 63 Subpart Q, *NESHAP for Industrial Process Cooling Towers*, applies to cooling towers operating with chromium-based water treatment chemicals that are located at facilities that are major sources of HAP. The only requirement for affected sources is to utilize water treatment chemicals that are not chromium based. The new cooling tower water treatment chemicals will not be chromium based, so this regulation will not apply to the proposed cooling tower.

4.4.3. 40 CFR Part 63 Subpart DDDDD, Industrial Boilers and Process Heaters

Subpart DDDDD, National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters, establishes national emission standards for HAPs emitted from industrial boilers and process heaters located at major HAP sources.¹⁸

The following emission limits will apply to the “new” Biomass Cogeneration Boiler upon startup:

- 0.0098 lb/MMBtu filterable PM/ PM₁₀/ PM_{2.5}
- 230 ppm CO at 3% O₂ on a short-term/ 3 hour average or 310 ppm CO at 3% O₂ on a 30-day rolling average
- 0.022 lb/MMBtu hydrogen chloride limit
- 0.8 lb/TBtu Mercury limit

4.4.4. 40 CFR Part 63 Subpart UUUUU, Electric Utility Steam Generating Units

40 CFR 63 Subpart UUUUU, *NESHAP for Electric Utility Steam Generating Units*, applies to certain oil- and coal-fired electric generating units. The Biomass Cogeneration Boiler will not fire either of these fuels and is therefore not subject to this rule.

4.5. COMPLIANCE ASSURANCE MONITORING

Under 40 CFR 64, Compliance Assurance Monitoring (CAM), facilities are required to prepare and submit monitoring plans for certain emission units with the initial or renewal Title V operating permit application. The CAM Plans provide an on-going and reasonable assurance of compliance with emission limits. Under the general applicability criteria, this regulation only applies to emission units that use a control device to achieve compliance with an emission limit and whose pre-controlled emission levels exceed the major source thresholds under the Title V permitting program unless such units meet a specified exemption.

For an emission unit whose post-controlled emissions are greater than the major source thresholds (referred to as large pollutant-specific emission units [PSEU] in the rule), a CAM plan is required to be submitted with the initial Title V operating permit application. For emission units whose post-

¹⁸ NESHAP Subpart DDDDD is currently stayed for reconsideration (76 FR 28662, May 18, 2011).

controlled emissions are less than the major source emission thresholds, a CAM plan is not required to be submitted until the first Title V permit renewal application.¹⁹

The following PSEUs are exempt from CAM applicability:

- Units subject to emission limitations under NSPS or NESHAPs standards promulgated after November 15, 1990.
- Emissions limitations for which a continuous compliance demonstration method (e.g., CEMS) is specified in a Part 70 permit.

The proposed Biomass Cogeneration Boiler has precontrolled and or post-controlled emissions for pollutants that will utilize control devices exceeding 100 tpy for NO_x, particulate matter (PM/PM₁₀/PM_{2.5}), and SO₂. NO_x emissions are subject to NSPS standards established after 2005 and will be measured using CEMS and is therefore exempt from CAM for NO_x. Particulate matter is subject to monitoring subject to the recently promulgated boiler NEHSAP and is therefore exempt from CAM for particulate matter. Sulfur dioxide will be monitored with a SEMS and is therefore exempt from CAM for SO₂.

It is uncertain whether uncontrolled emissions associated with either the flyash silo or sorbent silo will exceed the Title V permitting threshold for particulate matter, as final design has not been made. However, since post control emissions are less than 100 tpy, CAM Plans for this unit will not be required until Title V permit renewal.

4.6. RISK MANAGEMENT PROGRAM

Subpart B of 40 CFR Part 68 outlines requirements for risk management prevention plans pursuant to Section 112(r) of the Clean Air Act. Applicability of the subpart is determined based on the type and quantity of chemicals stored at the facility. P&GPP has evaluated the amount of Section 112(r) substances proposed to be stored at the facility and has determined that no substance is stored in a quantity above the triggering threshold (the 19% aqueous ammonia planned to be utilized by the facility is below the % ammonia RMP threshold). Thus, the facility is not subject to the RMP requirements. However, the facility is subject to the provisions of the CAAA General Duty Clause, Section 112, as it pertains to accidental releases of hazardous materials.

4.7. TITLE V OPERATING PERMIT PROGRAM

40 CFR 70 establishes the federal Title V operating permit program. Georgia has incorporated the provisions of the federal program in GRAQC 391-3-1-.03(10) *Title V Operating Permits*. The major source thresholds with respect to the Georgia Title V operating permit program for sources in attainment areas are 10 tons per year of a single HAP, 25 tpy of any combination of HAP, or 100 tpy of a criteria pollutant. As stated previously, the P&GPP facility is a major Title V facility for criteria pollutants and HAPs and permit requirements pursuant to this application will be incorporated into the Title V permit.

¹⁹ 40 CFR 64.5

4.8. ACID RAIN PROGRAM

In order to reduce acid rain in the United States and Canada, Title IV (40 CFR 72 *et seq.*) of the Clean Air Act Amendments of 1990 established the Acid Rain Program to substantially reduce SO₂ and NO_x emissions from electric utility plants. Affected units are specifically listed in Tables 1 and 2 of 40 CFR 73.10 under Phase I of the program. Under Phase II implementation, the Acid Rain Program applies to fossil fuel-fired combustion sources that drive generators for the purposes of generating electricity for sale.

Under the startup scenario that employs natural gas as the auxiliary fuel, the proposed Biomass Cogeneration Boiler at Albany facility will fire fossil fuel and thus will meet the definition of affected source under the Acid Rain regulations. P&GPP will comply with the Acid Rain requirements and apply for and obtain an Acid Rain permit prior to commencement of operation.

4.9. STRATOSPHERIC OZONE PROTECTION REGULATIONS

The requirements originating from Title VI of the Clean Air Act, entitled *Protection of Stratospheric Ozone*, are contained in 40 CFR 82. Subparts A through E and Subparts G and H are not expected to be applicable to the Albany facility. 40 CFR 82 Subpart F, *Recycling and Emissions Reduction*, potentially applies if the facility maintains, services, or disposes of appliances that utilize Class I or Class II ozone depleting substances. Subpart F generally requires persons completing the repairs, service, or disposal to be properly certified. All repairs, service, and disposal of ozone depleting substances from any chillers and air conditioners will be completed by a certified technician.

4.10. STATE REGULATORY REQUIREMENTS

In addition to federal air regulations, GRAQC 391-3-1 establishes regulations applicable at the emission unit level (source specific) and at the facility level for stationary sources. The rules also contain requirements related to the need for construction and/or operating permits.

4.10.1. GRAQC 391-3-1-.02(2)(b), Visible Emissions

This regulation limits the opacity from all sources to 40%, provided that the source is not subject to some other emission limitation under GRAQC 391-3-1-.02(2).²⁰ This regulation will be applicable to the sorbent silo, flyash silo, and the cooling tower. The proposed Biomass Cogeneration Boiler, however, will be subject to another opacity limit under GRAQC 391-3-1-.02(2)(d).

4.10.2. GRAQC 391-3-1-.02(2)(d), Fuel-Burning Equipment

This regulation limits PM emissions from all fuel-burning equipment. It also limits opacity and NO_x emissions from equipment constructed or modified after January 1, 1972. Georgia defines fuel-burning equipment as:

...equipment the primary purpose of which is the production of thermal energy from the combustion of any fuel. Such equipment is generally that used for, but not limited to, heating water, generating or superheating steam, heating air as in warm air furnaces, furnishing

²⁰ GRAQC 391-3-1-.02(2)(b)1

*process heat indirectly, through transfer by fluids or transmissions through process vessel walls.*²¹

The main usage of the proposed Biomass Cogeneration Boiler will be the generation of steam, thus subjecting the boiler to this regulation; no other equipment at the Albany facility is primarily used for the production of thermal energy.

For the proposed Biomass Cogeneration Boiler, which will be constructed after January 1, 1972 and will be greater than 250 MMBtu/hr, this rule establishes a PM limit of 0.10 lb/MMBtu and a 20% opacity limit (except one 6-minute period per hour of up to 27%).

Rule (d) also has a NO_x limit of 0.2 lb/MMBtu for fossil fuel boilers greater than 250 MMBtu/hr. As the rule does not specify that the heat input from the fossil fuel itself must be greater than 250 MMBtu/hr, the Rule (d) NO_x limit will apply during startup operations. The applicable standard that will apply during startup would be 0.2 lb/MMBtu. Since the natural gas burners are rated for 0.10 lb/MMBtu, the Biomass Cogeneration Boiler will comply with this regulation.

4.10.3. GRAQC 391-3-1-.02(2)(e), PM Emissions from Manufacturing Processes

This regulation, commonly known as the process weight rule (PWR), establishes PM limits for all sources if not specified elsewhere. The PM emissions are limited based on the following equations (for equipment constructed or modified after July 2, 1968), where equation (a) applies to sources with a process input rate of less than or equal to 30 ton/hr, while equation (b) applies to sources with a process input rate of more than 30 ton/hr:²²

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

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

where: E = allowable PM emission rate [lb/hr]

P = process input weight rate [tons/hr]

This regulation is expected to apply to the sorbent silo, flyash silo, and cooling tower. The sorbent silo throughput is 20 tph (20 ton load), and the particulate emission limit is 30.5 lb/hr. Emissions of 0.08 lbs/hr for the sorbent silo are shown in Appendix B and are well below the emission limit.

The flyash silo throughput is also assumed to be 10 tph, and the particulate emission limit is 19.2 lb/hr. Emissions of 0.042 lbs/hr for the flyash silo are shown in Appendix B and are well below the emission limit.

The cooling tower throughput is over 30 tph throughput so equation (b) is used with a throughput of 6,450 tph, and the particulate emission limit is 104 lb/hr. Emissions of 0.05 lbs/hr for the cooling tower are shown in Appendix B and are well below the emission limit.

Since the proposed Biomass Cogeneration Boiler will be subject to a PM limit under Rule (d), this rule will not apply to the boiler.²³

²¹ GRAQC 391-3-1-.01(cc)

²² GRAQC 391-3-1-.02(2)(e)(1)(i)

²³ GRAQC 391-3-1-.02(2)(d)

4.10.4. GRAQC 391-3-1-.02(2)(g), SO₂

This regulation applies to boilers with fossil fuel firing capacities greater than 250 MMBtu/hr. The maximum heat input capacity for natural gas will be 200 MMBtu/hr, so this regulation does not apply.

4.10.5. GRAQC 391-3-1-.02(2)(n), Fugitive Dust

This regulation requires facilities to take reasonable precautions to prevent fugitive dust from becoming airborne. The only source with more than negligible fugitive emissions is the biomass storage pile. However, due to the high moisture content of stored biomass, opacity will be well below 20% at all times..

4.10.6. GRAQC 391-3-1-.02(2)(uu), Visibility Protection

This regulation requires Georgia EPD to provide an analysis of a source's anticipated impact on visibility in any federal Class I area to the appropriate Federal Land Manager (FLM). Due to the low emissions associated with this project, the AQRV impact analysis for regional haze has been waived for this project.

4.10.7. GRAQC 391-3-1-.02(2)(jjj), NO_x from Electric Utility Steam Generating Units

This regulation limits NO_x emissions from electric utility steam generating units located in or near the original Atlanta 1-hour ozone nonattainment area. Albany facility is not located within the geographic area covered by this rule.

4.10.8. GRAQC 391-3-1-.02(2)(lll), NO_x from Fuel-Burning Equipment

This regulation limits NO_x emissions from fuel-burning equipment with capacities between 10 and 250 MMBtu/hr that are located in or near the original Atlanta 1-hour ozone nonattainment area. Albany facility is not located within the geographic area covered by this rule.

4.10.9. GRAQC 391-3-1-.02(2)(rrr), NO_x from Small Fuel-Burning Equipment

This regulation specifies requirements for fuel-burning equipment with capacities of less than 10 MMBtu/hr located in or near the original Atlanta 1-hour ozone nonattainment area. Albany facility is not located within the geographic area covered by this rule.

4.10.10. GRAQC 391-3-1-.02(2)(sss), Multipollutant Control for Electric Utility Steam Generating Units

This regulation limits the operation of specific electric utility steam generating units. As the proposed P&GPP proposed emission units will not contain any of the units specified by this regulation, Rule (sss) will not apply.

4.10.11. GRAQC 391-3-1-.02(2)(ttt), Mercury Emissions from New Electric Generating Units

This regulation limits the emission of mercury from affected units installed on or after January 1, 2007. For the purposes of this subsection, an “affected unit” refers to a “stationary coal-fired boiler or a stationary coal-fired combustion turbine.” The Biomass Cogeneration Boiler will solely fire biomass and natural gas and therefore will not be considered a “coal-fired” unit. Hence, Rule (ttt) will not apply.

4.10.12. GRAQC 391-3-1-.02(3), Sampling

This regulation requires any sampling, computation, and analysis to determine compliance with any emission limits or standards established by the Georgia SIP be completed in accordance with Georgia EPD’s *Procedures for Testing and Monitoring Sources of Air Pollutants*. The proposed equipment will comply with the applicable portions of this rule as required.

4.10.13. GRAQC 391-3-1-.02(5), Open Burning

This regulation imposes restrictions on open burning activities. The regulation specifies what type of burning is permitted, when, and limits opacity to 40%. P&GPP shall comply with the requirements of this regulation in the event of performing open burning.

4.10.14. GRAQC 391-3-1-.02(6)(b), Source monitoring

This regulation allows Georgia EPD to require a facility to install, maintain, and use monitoring devices necessary to determine compliance with any emission limits or standards established by the Georgia SIP. Such devices shall be installed, operated, calibrated, maintained, and information reported in accordance with the Georgia EPD’s *Procedures for Testing and Monitoring Sources of Air Pollutants*. P&GPP will comply with the applicable portions of this rule as required.

4.10.15. GRAQC 391-3-1-.02(7), PSD of Air Quality

This regulation incorporates the federal PSD program in 40 CFR 52.21, with certain revisions. PSD permitting requirements were discussed previously in this report.

4.10.16. GRAQC 391-3-1-.03(1), Construction (SIP) Permit

This regulation requires any facility which may result in air pollution to acquire a construction permit. The application for such a permit must be submitted on the forms provided by the Director well in advance of any critical date involved in the construction of the facility. In compliance with this regulation, the SIP forms have been prepared for the construction of the proposed Biomass Cogeneration Boiler and other emission units and are included as Appendix A to this application.

4.10.17. GRAQC 391-3-1-.03(10), Title V Operating Permits

This regulation incorporates the federal Title V operating permit program of 40 CFR 70. Applicability of this program was discussed previously in this report.

4.10.18. Incorporation of Federal Regulations by Reference

The following federal regulations are incorporated in the GRAQC by reference and were addressed previously in this application:

- GRAQC 391-3-1-.02(8) – NSPS
- GRAQC 391-3-1-.02(9) – NESHAP
- GRAQC 391-3-1-.02(10) – RMP
- GRAQC 391-3-1-.02(11) – CAM
- GRAQC 391-3-1-.02(12)-(13) – CAIR
- GRAQC 391-3-1-.13 – ARP

4.10.19. Non-Applicability of Other SIP Rules

A thorough examination of the Georgia SIP rule applicability to P&GPP reveals many SIP regulations that do not apply or impose no additional requirements on operations. Such SIP rules include those specific to a particular type of industrial operation and/or those specific to sources located within the metro Atlanta ozone nonattainment area.

4.11. SHUTDOWN OF BOILER B002

As discussed earlier, following completion of the shakedown period for the new cogeneration boiler, Boiler B002 will be formally decommissioned. In order to ensure the federal enforceability of the shutdown and to ensure the P&GPP Title V permit no longer requires compliance with applicable requirements for the boiler following decommissioning, P&GPP requests that the following condition (or similar verbiage) be added to the facility Title V permit:

“Following completion of the shakedown period for Biomass Cogeneration Boiler B004, not to exceed 180 days after first firing, P&GPP shall permanently shut down Boiler B002 and is no longer required to comply with any terms and conditions of this permit that are associated with the operation of Boiler B002.”

4.12. SUMMARY OF APPLICABLE EMISSION STANDARDS AND COMPLIANCE REQUIREMENTS

A summary of the various applicable emission standards, associated monitoring requirements, and applicable reference stack test methods (if required) is provided in Table 4-2. Please note that the proposed BACT emission limits discussed in Section 5 are included in this table.

TABLE 4-2. SUMMARY OF APPLICABLE STANDARDS AND COMPLIANCE REQUIREMENTS

Emission Source	Emission Unit ID No.	Pollutant	Applicable Standard	Citation	Emission Standard	Monitoring Method	Monitored Limit	Monitoring Frequency	Averaging Period	Reference Test Method	Notes
Biomass Cogeneration Boiler	B004	PM	NESHAP	40 CFR 63 Subpart DDDDD	0.0098 lb/MMBtu	Bag Leak Detection System	5% alarms within averaging period	Continuous	6 months	Method 5D	
Biomass Cogeneration Boiler	B004	PM	NESHAP	40 CFR 63 Subpart DDDDD	0.0098 lb/MMBtu	Continuous Opacity Monitor	10%	Continuous	Daily block average	Method 5D	COMS is alternative monitoring option to BLDS monitor listed above
Biomass Cogeneration Boiler	B004	PM filterable	PSD/BACT	40 CFR 52.21	0.0098 lb/MMBtu	BLDS or COMS	Same as NESHAP	NESHAP	NESHAP	Method 5D	Proposed BACT limit is a 3-hour averaging period with compliance based on stack testing.
Biomass Cogeneration Boiler	B004	PM total	PSD/BACT	40 CFR 52.21	0.0268 lb/MMBtu	BLDS or COMS	Same as NESHAP	NESHAP	NESHAP	Method 5D and EPD-approved Condensable Method	
Biomass Cogeneration Boiler	B004	PM	NSPS	40 CFR 60 Subpart Db	0.03 lb/MMBtu	Bag Leak Detection System	Eliminate alarms within 3 hours	Continuous	Hourly	5D	
Biomass Cogeneration Boiler	B004	PM/Opacity	NSPS	40 CFR 60 Subpart Db	0.03 lb/MMBtu	Continuous Opacity Monitor	20% , except one 6-minute period/hr of 27%	Continuous	6 minutes	Method 9	COMS is alternative monitoring option to BLDS monitor listed above
Biomass Cogeneration Boiler	B004	NOx	NSPS	40 CFR 60 Subpart Db	10% annual capacity factor of fossil fuels	N/A	N/A	N/A	12 month rolling	N/A	Requesting a 10% annual capacity factor for fossil fuels. P&G will remain below the 10% capacity factor and will not be subject to NOx emission standards for NSPS Db.
Biomass Cogeneration Boiler	B004	Opacity	SIP	391-3-1-.02(2)(d)	20% , except one 6-minute period/hr of 27%	N/A	N/A	N/A	N/A	Method 9	
Biomass Cogeneration Boiler	B004	NOx	PSD/BACT	40 CFR 52.21	0.075 lb/MMBtu	CEMS	N/A	Continuous	Rolling 24-hour	Method 7E	
Biomass Cogeneration Boiler	B004	SO2	PSD/BACT	40 CFR 52.21	0.02 lb/MMBtu	CEMS	N/A	Continuous	See Note	See Note	Since CEMS is required under Acid Rain regulations, will be conducted in accordance with Part 75 requirements
Biomass Cogeneration Boiler	B004	CO	NESHAP	40 CFR 63 Subpart DDDDD	230 ppm @ 3% oxygen	Stack Test	N/A	Stack Test	3-hour average	Method 10, 10A or 10B	Alternative limit to 310 ppm @ 3% oxygen continuous limit
Biomass Cogeneration Boiler	B004	CO	NESHAP	40 CFR 63 Subpart DDDDD	310 ppm @ 3% oxygen	CEMS	N/A	Continuous	30 day rolling average	Method 10, 10A or 10B	
Biomass Cogeneration Boiler	B004	CO	PSD/BACT	40 CFR 52.21	0.10 lb/MMBtu	CEMS	N/A	Continuous	30 day rolling average	Method 10, 10A or 10B	
Biomass Cogeneration Boiler	B004	VOC	PSD/BACT	40 CFR 52.21	0.007 lb/MMBtu	N/A	N/A	N/A	N/A	Method 25 or 25A	
Biomass Cogeneration Boiler	B004	HCl	NESHAP	40 CFR 63 Subpart DDDDD	0.022 lb/MMBtu	Sorbent Injection Rate	Per mfr specification	Continuous	Hourly	Method 26	Actual injection rates pending final design and will be maintained until performance testing
Biomass Cogeneration Boiler	B004	Hg	NESHAP	40 CFR 63 Subpart DDDDD	0.8 lb/TBtu	Carbon Injection Rate	Per mfr specification	Continuous	Hourly	Any of the performance methods specified in Table 5 of Subpart DDDDD	Actual injection rates pending final design and will be maintained until performance testing
Flyash & Sorbent Silos	FAS1 & SS1	PM	PSD/BACT	40 CFR 52.21	0.005 gr/cf	Pressure Drop Monitoring	Per mfr specification	Continuous	Hourly	Method 5	
Flyash & Sorbent Silos and Cooling Tower	FAS1, SS1 & CT	Opacity	SIP	391-3-1-02(2)(b)	40% opacity	N/A	N/A	N/A	N/A	Method 9	
Flyash & Sorbent Silos	FAS1 & SS1	PM	SIP	391-3-1-02(2)(e)	$E = 4.10 \times P^{0.67}$	0.005 gr/cf	Pressure Drop Monitoring	Per mfr specification	Hourly	Method 5	
Cooling Tower	CT	PM	PSD/BACT	40 CFR 52.21	0.0005% drift loss	N/A	N/A	N/A	N/A	Method 5	No monitoring, based on mfr design specification
Cooling Tower	CT	PM	SIP	391-3-1-02(2)(e)	$E = 55.0 \times P^{0.11} - 40$	N/A	N/A	N/A	N/A	Method 5	No monitoring, based on mfr design specification

5. BACT ASSESSMENT

This section discusses the regulatory basis for BACT, approach used in completing the BACT analyses, and the BACT analyses for P&GPP. Supporting documentation is included in Appendix D.

5.1. BACT DEFINITION

The requirement to conduct a BACT analysis is set forth in the PSD regulations [40 CFR 52.21(j)(2)]:

(j) Control Technology Review.

(2) A new major stationary source shall apply best available control technology for each regulated NSR pollutant that it would have the potential to emit in significant amounts.

BACT is defined in the PSD regulations [40 CFR 52.21(b)(12)] as:

...an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR parts 60 and 61.

[primary BACT definition]

If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results.

[allowance for secondary BACT standard under certain conditions]

The primary BACT definition can be best understood by breaking it apart into its separate components.

5.1.1. Emission Limitation

...an emissions limitation

First and foremost, BACT is an emission limit. While BACT is prefaced upon the application of technologies to achieve that limit, the final result of BACT is a limit. In general, this limit would be an emission rate limit of a pollutant (i.e., lb/MMBtu).²⁴

²⁴ Emission limits can be broadly differentiated as “rate-based” or “mass-based.” For a boiler, a rate-based limit would typically be in units of lb/MMBtu (mass emissions per heat input). In contrast, a typical mass-based limit would be in units of lb/hr (mass emissions per time).

5.1.2. Case-by-Case Basis

...a case-by-case basis, taking into account energy, environmental and economic impacts and other costs

Unlike many of the Clean Air Act programs, the PSD program's BACT evaluation is case-by-case. As noted by U.S. EPA,

The case-by-case analysis is far more complex than merely pointing to a lower emissions limit or higher control efficiency elsewhere in a permit or a permit application. The BACT determination must take into account all of the factors affecting the facility, such as the choice of [fuel]... The BACT analysis, therefore, involves judgment and balancing.²⁵

To assist applicants and regulators with the case-by-case process, in 1987 U.S. EPA issued a memorandum that implemented certain program initiatives to improve the effectiveness of the PSD program within the confines of existing regulations and state implementation plans.²⁶ Among the initiatives was a "top-down" approach for determining BACT. In brief, the top-down process suggests that all available control technologies be ranked in descending order of control effectiveness. The most stringent or "top" control option is the default BACT emission limit unless the applicant demonstrates, and the permitting authority in its informed opinion agrees, that energy, environmental, and/or economic impacts justify the conclusion that the most stringent control option is not achievable in that case. Upon elimination of the most stringent control option based upon energy, environmental, and/or economic considerations, the next most stringent alternative is evaluated in the same manner. This process continues until BACT is selected.

The five steps in a top-down BACT evaluation can be summarized as follows:

- Step 1. Identify all possible control technologies;
- Step 2. Eliminate technically infeasible options;
- Step 3. Rank the technically feasible control technologies based upon emission reduction potential;
- Step 4. Evaluate ranked controls based on energy, environmental, and/or economic considerations;
- and
- Step 5. Select BACT.

While the top-down BACT analysis is a procedural approach suggested by U.S. EPA policy, this approach is not specifically mandated as a statutory requirement of the BACT determination. As discussed in Section 5.1.1, the BACT limit is an emissions limitation and does not require the installation of any specific control device.

5.1.3. Achievable

...based on the maximum degree of reduction ...[that Georgia EPD] ... determines is achievable ... through application of production processes or available methods, systems and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques

²⁵ U.S. EPA Responses to Public Comments on the Proposed PSD Permit for the Desert Rock Energy Facility, July 31, 2008, p.41-42.

²⁶ Memo dated December 1, 1987, from J. Craig Potter (EPA Headquarters) to EPA Regional Administrators, titled "Improving New Source Review Implementation."

BACT is to be set at the lowest value that is achievable. However, there is an important distinction between emission rates achieved at a specific time on a specific unit, and an emission limitation that a unit must be able to meet continuously over its operating life. As discussed by the DC Circuit Court of Appeals

In *National Lime Ass'n v. EPA*, 627 F.2d 416, 431 n.46 (D.C. Cir. 1980), we said that where a statute requires that a standard be "achievable," it must be achievable "under most adverse circumstances which can reasonably be expected to recur."²⁷

U.S EPA has reached similar conclusions in prior determinations for PSD permits.

Agency guidance and our prior decisions recognize a distinction between, on the one hand, measured 'emissions rates,' which are necessarily data obtained from a particular facility at a specific time, and on the other hand, the 'emissions limitation' determined to be BACT and set forth in the permit, which the facility is required to continuously meet throughout the facility's life. Stated simply, if there is uncontrollable fluctuation or variability in the measured emission rate, then the lowest measured emission rate will necessarily be more stringent than the "emissions limitation" that is "achievable" for that pollution control method over the life of the facility. Accordingly, because the "emissions limitation" is applicable for the facility's life, it is wholly appropriate for the permit issuer to consider, as part of the BACT analysis, the extent to which the available data demonstrate whether the emissions rate at issue has been achieved by other facilities over a long term.²⁸

Thus, BACT must be set at the lowest feasible emission rate recognizing that the facility must be in compliance with that limit for the lifetime of the facility on a continuous basis. Thus, while viewing individual unit performance can be instructive in evaluating what BACT might be, any actual performance data must be viewed carefully, as rarely will the data be adequate to truly assess the performance that a unit will achieve during its entire operating life. While statistical variability of actual performance can be used to infer what is "achievable," such testing requires a detailed test plan akin to what teams in U.S. EPA use to develop MACT standards over a several year period, and is far beyond what is reasonable to expect of an individual source. In contrast to limited snapshots of actual performance data, emission limits from similar sources can reasonably be used to infer what is "achievable."²⁹

To assist in meeting the BACT limit, the source must consider production processes or available methods, systems or techniques, as long as those considerations do not redefine the source (see Section 5.2)

²⁷ As quoted in *Sierra Club v. EPA* (97-1686).

²⁸ EPA Environmental Appeals Board decision, *In re: Newmont Nevada Energy Investment L.L.C.* PSD Appeal No. 05-04, decided December 21, 2005. Environmental Administrative Decisions, Volume 12, Page 442.

²⁹ Emission limits must be used with care in assessing what is "achievable." Limits established for facilities which were never built must be viewed with care, as they have never been demonstrated and that company never took a significant liability in having to meet that limit. Likewise, permitted units which have not yet commenced construction must also be viewed with special care for similar reasons.

5.1.4. Floor

Emissions [shall not] exceed ...40 CFR Parts 60 and 61

The least stringent emission rate allowable for BACT is any applicable limit under either New Source Performance Standards (NSPS – Part 60) or National Emission Standards for Hazardous Air Pollutants (NESHAP – Part 61). While Clean Air Act section 112(b)(6) precludes use of Part 63 NESHAPs from establishing the floor, such standards are considered informative, representing maximum achievable control technology. State SIP limitations must also be considered when determining the floor.

5.2. BACT REQUIREMENT

The BACT requirement applies to each new or modified emission unit from which there are emissions increases of pollutants subject to PSD review. The proposed facility is subject to PSD permitting for NO_x, SO₂, PM, PM₁₀, PM_{2.5}, and CO and thus, subject to BACT for these pollutants. The Biomass Cogeneration Boiler and auxiliary equipment are subject to BACT for each pollutant requiring PSD permitting that is emitted by the particular piece of equipment. The following emission units and pollutants were considered in the BACT analysis; refer to Section 2 of this report for a detailed discussion of each emission unit:

- Biomass Cogeneration Boiler: NO_x, SO₂, PM, PM₁₀, PM_{2.5}, CO, VOC
- Biomass Storage: PM, PM₁₀, PM_{2.5}, VOC
- Sorbent Storage: PM, PM₁₀, PM_{2.5}
- Cooling Tower: PM, PM₁₀, PM_{2.5}
- Hogger: VOC
- Fugitive Road Emissions: PM, PM₁₀, PM_{2.5}

Note the same control techniques that reduce PM also reduce filterable PM₁₀ and PM_{2.5}. The PM₁₀ BACT analyses will satisfy BACT for PM and PM_{2.5}. In the prepared BACT analyses, references to PM₁₀ are also relevant for PM and PM_{2.5}, and neither PM nor PM_{2.5} are explicitly addressed separately.

5.3. BACT ASSESSMENT METHODOLOGY

The following sections provide detail on the BACT assessment methodology utilized in preparing the BACT analysis for the proposed emission units. As previously noted, the minimum control efficiency to be considered in a BACT assessment must result in an emission rate less than or equal to any applicable NSPS or Part 61 NESHAP emission rate for the source. Although the definition of ABCT only extends to Part 61 NESHAPs and Section 112(b)(6) of the Clean Air Act precludes use of Part 63 NESHAPs from establishing BACT, for purposes of this application, Part 63 NESHAPs will also conservatively establish the BACT floor. The following NSPS or NESHAP emission limits will apply to proposed equipment and effectively set the floor for BACT for these units for certain pollutants:

- Biomass Cogeneration Boiler
 - PM limit of 0.030 lb/MMBtu (NSPS Subpart Db)
 - PM limit of 0.0098 lb/MMBtu (Part 63 NESHAP Subpart DDDDD)
 - If firing natural gas NO_x limit of 0.20 lb/MMBtu (NSPS Subpart Db)

- Sorbent Injection System
 - Covered under NSPS OOO but no limits on PSD-regulated pollutants

5.3.1. Identification of Potential Control Technologies

Potentially applicable emission control technologies were identified by researching the U.S. EPA control technology database, technical literature, control equipment vendor information, state permitting authority files, and by using process knowledge and engineering experience. The Reasonably Available Control Technology (RACT)/BACT/Lowest Achievable Emission Rate (LAER) Clearinghouse (RBLC), a database made available to the public through the U.S. EPA's Office of Air Quality Planning and Standards (OAQPS) Technology Transfer Network (TTN), lists technologies and corresponding emission limits that have been approved by regulatory agencies in permit actions. These technologies are grouped into categories by industry and can be referenced in determining what emissions levels were proposed for similar types of emissions units.

Trinity performed searches of the RBLC database to start to identify the emission control technologies and emission levels that were determined by permitting authorities as BACT within the past ten years for emission sources comparable to the proposed Biomass Cogeneration Boiler. The following categories were searched:

- Biomass (Wood) Boilers > 250 MMBtu/hr (RBLC Code 11.120)
- Other Fuel Combination Boilers > 250 MMBtu/hr (RBLC Code 11.900)
- Solid Fuel Boilers > 100 MMBtu/hr and < 250 MMBtu/hr (RBLC Code 12.120)
- Other Fuel Combination Boilers > 100 MMBtu/hr and < 250 MMBtu/hr (RBLC Code 12.900)
- Miscellaneous Boilers, Furnaces, and Process Heaters (RBLC Code 19.600)

Upon completion of the RBLC search, Trinity then reviewed relevant vendor information, pending permit applications, and issued permits not included in the RBLC. Appendix D presents a summary table of relevant BACT determinations for biomass or mixed fuels boilers predominately firing biomass.

Additional RBLC searches were performed to identify control options for the auxiliary equipment as permitted within the past ten years. The following categories were searched:

- Biomass Storage and Handling (RBLC Codes 30.290, 30.390, 30.490, 30.510, 30.999)
- Lime Handling and Storage (RBLC Code 90.019), as a surrogate for the duct injection reagent storage
- Industrial Process Cooling Tower (RBLC Code 99.009)
- Paved Roads (RBLC Code 99.140)

5.3.2. Economic Feasibility Calculation Process

Economic analyses were performed to compare total costs (capital and annual) for potential control technologies. Capital costs include the initial cost of the components intrinsic to the complete control system. Annual operating costs include the financial requirements to operate the control system on annual basis and include overhead, maintenance, outages, raw materials, and utilities.

The capital cost estimating technique used is based on a factored method of determining direct and indirect installation costs. That is, installation costs are expressed as a function of known equipment

costs. This method is consistent with the latest U.S. EPA OAQPS guidance manual on estimating control technology costs.³⁰

Total Purchased Equipment Cost represents the delivered cost of the control equipment, auxiliary equipment, and instrumentation. Auxiliary equipment consists of all the structural, mechanical, and electrical components required for the efficient operation of the device. Auxiliary equipment costs are estimated as a straight percentage of the equipment cost. Direct installation costs consist of the direct expenditures for materials and labor for site preparation, foundations, structural steel, erection, piping, electrical, painting and facilities. Indirect installation costs include engineering and supervision of contractors, construction and field expenses, construction fees, and contingencies. Other indirect costs include equipment startup, performance testing, working capital, and interest during construction.

Annual costs are comprised of direct and indirect operating costs. Direct annual costs include labor, maintenance, replacement parts, raw materials, utilities, and waste disposal. Indirect operating costs include plant overhead, taxes, insurance, general administration, and capital charges. Replacement part costs, such as the cost of replacement bags for the baghouse, were included where applicable, while raw material costs were estimated based upon the unit cost and annual consumption. With the exception of overhead, indirect operating costs were calculated as a percentage of the total capital costs. The indirect capital costs were based on the capital recovery factor (CRF) defined as:

$$CRF = \frac{i(1+i)^n}{(1+i)^n - 1}$$

where i is the annual interest rate and n is the equipment life in years. The equipment life is based on the normal life of the control equipment and varies on an equipment type basis. The same interest applies to all control equipment cost calculations. For this analysis, an interest rate of 7% was used based on information provided in the most recent OAQPS Control Cost Manual.³¹

Detailed cost analyses calculations are presented in Appendix D. Certain base capital and operating costs associated with pollution control options for P&GPP's proposed Biomass Cogeneration Boiler were based on use of information provided in a 2009 PSD permit application submitted for Oglethorpe's proposed Warren County Electric Generating Station, consisting of a 1,282 MMBtu fluidized bed boiler. Use of these estimates was considered reliable because of the similarity in size and exhaust stream characteristics of these combustion technologies. These estimates were based on detailed engineering cost studies with a high level of accuracy. The scaling techniques utilized in the analyses are based on standard engineering adjustment procedures and introduce only a nominal decrease in accuracy. However, due to the similarity of the exhaust streams and similar size of P&GPP's and Oglethorpe's projects, cost impacts provided in this application are well within the 30 percent margin of error allowed by EPA for estimation of cost impacts in BACT evaluations.³² It should be noted that this application includes evaluation of all of the same control options included in the Oglethorpe application and reached the same conclusions regarding cost impacts of

³⁰ U.S. EPA, *OAQPS Control Cost Manual*, 6th edition, EPA 452/B-02-001, July 2002.

http://www.epa.gov/ttn/catc/dir1/c_allchs.pdf

³¹ U.S. EPA, *OAQPS Control Cost Manual*, 6th edition, Section 2, Chapter 1, page 1-52.

http://www.epa.gov/ttn/catc/dir1/c_allchs.pdf

³² New Source Review Workshop Manual (p. B-35), US EPA, 1990.

each control option, resulting in proposed emission levels very similar to those proposed by Oglethorpe.

5.4. BIOMASS COGENERATION BOILER - NO_x BACT

5.4.1. Background on Pollutant Formation

In industrial boiler and furnace combustion processes, NO_x is formed by two fundamentally different mechanisms: fuel NO_x and thermal NO_x. Technical literature suggests that NO_x formation from wood and other biomass combustion is primarily fuel NO_x.³³

“Fuel NO_x” forms when the fuel bound nitrogen compounds are converted into nitrogen oxides. The amount of fuel bound nitrogen converted to fuel NO_x depends largely upon the fuel type, nitrogen content of the fuel, air supply, and boiler design (including combustion temperature). The reaction between elemental nitrogen and oxygen to form nitrogen oxides happens very rapidly. Therefore, the primary mechanisms for reducing fuel NO_x involve creating a minimum amount of excess oxygen available to react with the fuel bound nitrogen throughout the combustion process.³⁴

NO_x formed in the high-temperature, post-flame region of the combustion equipment is “thermal NO_x.” Temperature is the most important factor, and at flame temperatures above 2,200°F, thermal NO_x formation increases exponentially.³⁵

NO formation is inherent in all high temperature combustion processes. Nitrogen dioxide (NO₂) can then be formed in a reaction between the NO and oxygen in the combustion gases. In stationary source combustion, little of the NO is converted to NO₂ before being emitted. However, the NO continues to oxidize in the atmosphere. For this reason, all NO_x emissions from the boiler stack are usually reported as NO₂.

5.4.2. Identification of Potential Control Techniques (Step 1)

Using the RBLC search and permit review results, as well as a review of technical literature, potentially applicable NO_x control technologies for biomass, non-fossil fuel-fired boilers were identified based on the principles of control technology and engineering experience for general combustion units (e.g., industrial boilers).³⁶

Pollution prevention options include:

- Flue Gas Recirculation (FGR)
- Fuel Staging (Reburning)
- Good Design and Operating Practices, including Overfire Air (Baseline)

³³ Webster, T.S. and S. Drennan. *Low NO_x Combustion of Biomass Fuels*. Coen Company, Inc. http://www.coen.com/i_html/white_lownoxbiom.html.

³⁴ Kraft, D.L. *Bubbling Fluid Bed Boiler Emissions Firing Bark & Sludge*. Barberton, OH: Babcock & Wilcox. September 1998. <http://www.babcock.com/library/pdf/BR-1661.pdf>.

³⁵ Kraft, D.L. *Bubbling Fluid Bed Boiler Emissions Firing Bark & Sludge*. Barberton, OH: Babcock & Wilcox. September 1998. <http://www.babcock.com/library/pdf/BR-1661.pdf>.

³⁶ Note control options were not considered if they were designed only for fossil fuel-fired boilers or other combustion sources (i.e., combustion turbines, engines): Xonon, SCONO_x/EM_x, THERMALONO_x, Rotating Opposed Fire Air, Pahlman Process.

Pollution reduction options include:

- Selective Non-Catalytic Reduction (SNCR)
- Selective Catalytic Reduction (SCR)
- Regenerative Selective Catalytic Reduction (RSCR)

These control technologies are briefly discussed in the following sections.

5.4.2.1. Flue Gas Recirculation

FGR reduces peak flame temperature, minimizing thermal NO_x, by recirculating a portion of the flue gas back into the combustion zone as a replacement for combustion air. The recirculated combustion products provide inert gases that lower the adiabatic flame temperature and overall oxygen concentration in the combustion zone.³⁷ As a result, FGR limits NO_x emissions by reduction of thermal NO_x only, making it ineffective for a fluidized bed combustion unit.

5.4.2.2. Fuel Staging (Reburning)

Also known as “reburning” or “off-stoichiometric combustion,” fuel staging is a technique where ten to twenty percent of the total fuel input is diverted to a second combustion zone downstream of the primary zone. The fuel in the secondary zone serves as a reducing agent; NO formed in the primary combustion zone is reduced to N₂.³⁸ This technique usually employs natural gas or distillate oil for the fuel in the secondary combustion zone.

5.4.2.3. Good Design and Operating Practices

NO_x formation can be most cost-effectively minimized by proper boiler operation and design practices. Operators can control the localized peak combustion temperature and combustion stoichiometry to minimize NO_x formation while achieving efficient fuel combustion. One of the most beneficial design characteristics of a fluidized bed boiler is that it utilizes air staging technology in the combustion process to reduce NO_x. This is accomplished by introducing the primary air through a distributor plate, to fluidize the bed, in quantities to keep the combustion in a fuel rich environment. This limits the amount of oxygen available to react with fuel bound nitrogen to form fuel NO_x. The secondary air is then introduced in one or more layers to raise the combustion zone and ensure complete combustion of the fuel. Good combustion practices at this stage play a pivotal role to ensure optimal operating conditions. NO_x emissions are reduced by limiting the amount of excess air, but other emissions are limited by complete combustion. Incomplete combustion in this stage would contribute to excess amounts of CO emissions.

Fluidized bed boiler operation also assists in prevention of NO_x formation by regulating the operating temperature of the boiler at a comparatively low temperature for combustion as compared to stoker boilers,³⁹ with typical CFB bed temperatures between 1,500 and 1,600 °F.⁴⁰ Due to the nature of NO_x formation, thermal NO_x formation would be negligible.

³⁷ Prasad, Arbind, “Air Pollution Control Technologies for Nitrogen Oxides,” *The National Environmental Journal*, May/June 1995.

³⁸ Ibid.

³⁹ Babcock & Wilcox, *Bubbling Fluidized-Bed Boilers Burning Biomass and Low-Cost Fuels*, 2008. Available at: www.babcock.com/library/pdf/e1013161.pdf

Overfire air (OFA), a staged combustion technique, is a fundamental part of a CFB boiler and reduces NO_x emissions by creating a “fuel-rich” zone via air staging (diverting a portion of the total amount of air required through separate ports). Conditions in such a zone result in lower peak temperatures and thus, lower NO_x emissions.

5.4.2.4. *Selective Non-Catalytic Reduction*

SNCR is an exhaust gas treatment process in which urea or ammonia is injected into the exhaust gas. The effectiveness of SNCR systems depends on several factors, including CO and SO₂ flue gas concentrations, flue gas temperature, residence time, and reagent and flue gas mixing. If high CO concentrations are present, then the reagent efficiency is decreased, and if high SO₂ concentrations are present, then the temperature for optimal performance is increased. Per the SNCR vendor, high temperatures, normally between 1,550 and 2,000°F, are necessary to promote the reaction between urea or ammonia (NH₃) and NO_x to form N₂ and water.

Outside of the design temperature window, the emissions are adversely affected. If the temperatures are too high, then the reagent may be oxidized, causing additional NO_x emissions. If the temperatures are too low, then the reaction between the reagent and NO_x is slowed, and emissions of the reagent will be present. A sufficient residence time and reagent mixing time are also necessary to ensure maximum NO_x reductions are achieved and no excess emissions of the reagent are present.⁴¹

5.4.2.5. *Selective Catalytic Reduction*

SCR is an exhaust gas treatment process in which ammonia or urea is injected into the exhaust gas upstream of a catalyst. The ammonia or urea reacts to form nitrogen (N₂) and water on the surface of the catalyst, which typically has a temperature between 450 and 850° F. The installation of a SCR system on a fluidized bed boiler could be either on the “high dust” or “hot side,” between the economizer and air heater, or on the “tail end” or “cold side,” downstream of the particulate control and air heater.

In the SCR process, urea or ammonia, stored either as an anhydrous ammonia or aqueous solution, is injected into the exhaust upstream of the catalyst. The exhaust/ammonia (or urea) mixture passes over the catalyst, which lowers the activation energy of the NO decomposition reaction, therefore, lowering the temperature necessary to carry out the reaction.

As previously mentioned, a SCR control device is typically installed on either the hot side, high dust or the cold end. For a hot side, high dust SCR setup, the SCR is placed after the economizer and before the air heater and particulate control units. This situation allows for the placement of the system to be within the necessary temperature window for successful SCR operation; however, the high level of particulates present in the flue gas at this location can damage the catalyst, either by physical damage or chemical contamination, resulting in significant downtime associated with cleaning or replacing the catalysts.

⁴⁰ Woodruff, Everett B., Herbert B. Lammers, and Thomas F. Lammers, *Steam Plant Operation*, 2004, page 106.

⁴¹ Kitto, J.B. *Air Pollution Control For Industrial Boiler Systems*. Barberton, OH: Babcock & Wilcox. November 1996. <http://www.babcock.com/library/pdf/BR-1624.pdf>

Another SCR placement option is on the cold side, after the air heaters and particulate control device. However, as the name implies, the temperature in this location is low, typically around 300 to 350° F, significantly below the required temperature range for an SCR. At this lower temperature, ammonia does not readily react with NO_x, and both would be emitted to the atmosphere. Thus, heaters must be used to heat the flue gas back up to at least 470°F or higher. When considering a cold side catalyst, the technology discussed in the following section is most appropriate as it minimizes the fuel penalty for the exhaust gas reheat.

5.4.2.6. Regenerative Selective Catalytic Reduction (RSCR)

Babcock Power's patented RSCR systems are "tail-end" SCR systems on the cold side, after the particulate control device. Such a system setup has a relatively limited amount of particulates and chemicals present in the flue gas, which limits the damage and degradation of the catalysts used in the system. However, the flue gas temperature is much less than the necessary temperature range for the successful reaction between the ammonia or urea injections with the NO_x of the flue gas. For this reason, the flue gas is temporarily reheated to a temperature in which NO_x successfully reacts with the ammonia or urea injections.

To minimize fuel consumption, the heating of the flue gas is accomplished using the "regenerative" heating technology, in a system analogous to a regenerative thermal oxidizer (RTO) as might be used to control an organics stream.⁴² In the RSCR configuration, the reagent is first introduced upstream of the RSCR unit. The flue gas/reagent mixture (previously cleaned of particulate matter) then enters one end of the system, where the flue gas mixture travels up through the (hot) ceramic heat retention canister to be reheated. The flue gas mixture then flows through the catalyst section, where the ammonia reacts with the NO_x to form nitrogen and water. After the catalyst, the flue gas flows through a "retention" chamber, where a burner reheats the flue gas slightly. From this chamber, the flue gas then flows through the (cold) second canister and is used to heat this canister's ceramic heat retention block. Once this cycle is complete, the air flow is diverted, so that the second canister is the inlet for the "cold" flue gas, and the first canister is the outlet for the cleaned flue gas.⁴³ The RSCR approach minimizes the supplemental fuel required to reheat the cold exhaust gas.

5.4.3. Elimination of Technically Infeasible Control Options (Step 2)

After the identification of potential control options, the second step in the BACT assessment is to eliminate technically infeasible options. A control option is eliminated from consideration if there are process-specific conditions that would prohibit the implementation of the control or if the highest control efficiency of the option would result in an emission level that is higher than any applicable regulatory limits.

All control technologies and techniques identified in this section are technically infeasible for application to the proposed Biomass Cogeneration Boiler. Reasons for eliminating each option are identified below.

⁴² In contrast, a traditional cold-side SCR would use a Ljungstrom-style air heater to reheat the flue gas at a much greater energy penalty.

⁴³ Abrams, Richard F. (Babcock Power Environmental, Inc.) and Kevin Toupin (Riley Power, Inc.). *Efficient and Low Emission Stoker Fired Biomass Boiler Technology in Today's Marketplace*. Worcester, MA: Babcock Power Environmental, Inc. March 2007. <http://www.babcockpower.com/pdf/t-200.pdf>

5.4.3.1. Flue Gas Recirculation

FGR requires considerable equipment for carrying the recirculated flue gas. For recirculation rates greater than 15 percent, an additional fan is needed. The recirculation fan is a specialty fan that must be able to withstand the high temperature and high particulate loading in the flue gas stream. High particulate loading in the flue gas stream is of particular concern since the Biomass Cogeneration Boiler's fuel is biomass.

Further, FGR does not significantly reduce NO_x emissions when firing biomass in a boiler since the majority of NO_x emissions from biomass-fired fluidized bed boilers arise from fuel bound nitrogen. Therefore, FGR (which controls thermal NO_x) does not effectively reduce the NO_x emissions from biomass fluidized bed boilers. Furthermore, the RBLC indicates FGR has not been successfully demonstrated on fluidized bed boilers combusting primarily biomass.⁴⁴

Were FGR not eliminated at this step, its control effectiveness would fall below SNCR.

5.4.3.2. Fuel Staging (Reburning)

Fuel staging requires usage of natural gas or distillate oil in a secondary combustion zone downstream of the primary zone. The Biomass Cogeneration Boiler will only utilize biomass during normal operations (natural gas as a starter fuel only) and therefore, will be unable to utilize this technique. Further, this technique employs FGR, which is considered infeasible for biomass-fired boilers due to its inability to minimize fuel NO_x, the primary component of NO_x from biomass combustion.

Were fuel staging not eliminated at this step, its control effectiveness would fall below SNCR.

5.4.4. Rank of Remaining Control Technologies (Step 3)

The third of the five steps in the top-down BACT assessment procedure is to rank technically feasible control technologies by control effectiveness. The remaining control technologies, ranked by effectiveness, are presented in Table 5-1.

TABLE 5-1. REMAINING NO_x CONTROL TECHNOLOGIES

Rank	Control Technology	Expected Emissions (24-hour average)
1	Tail End SCR/RSCR	0.06 lb/MMBtu
2	Hot End, High Dust SCR	0.06 lb/MMBtu
3	SNCR	0.075 lb/MMBtu
4	Good Design and Operating Practices (including OFA)	0.20 lb/MMBtu

⁴⁴ Note that FGR is listed as a potential technology for the No. 2 Power Boiler at the Weyerhaeuser Valliant, OK, facility. This boiler was permitted to burn "mixed fuels", which at a pulp and paper mill typically includes wood, oil, gas, and potentially coal. As such, this boiler is not comparable to a boiler designed to fire only biomass. Further, the Weyerhaeuser boiler was never constructed per permitting documents available on Oklahoma Department of Environmental Quality (ODEQ) website (for example: www.deq.state.ok.us/AQDnew/permitting/permitissue/97057-cp4.doc).

5.4.5. Evaluation of Most Stringent Controls (Step 4)

The fourth of the five steps in the top-down BACT assessment procedure is to evaluate the most effective control and document the results. This has been performed for each remaining control technology on the basis of economic, energy, and environmental considerations, and is described in the following sections.

5.4.5.1. Tail End SCR/RSCR

Tail end SCR or Babcock Power's RSCR works by reheating the flue gas to the necessary temperatures for the ammonia and NO_x to react to form nitrogen and water. While the regenerative heating reduces the required heat input, this reheating of the flue gas still represents a significant amount of auxiliary fuel that would be necessary for successful operation. Further, recent determinations and comments made by Georgia EPD confirm that it would not be economically feasible to re-heat the flue gas for the tail end application of a SCR on a biomass-fired fluidized bed boiler.⁴⁵

Tail end SCR control technology has been demonstrated on smaller wood-fired stoker boilers. The efficiency of this system on wood fired stoker boilers has successfully been determined at up to 80% NO_x; however, the uncontrolled NO_x emissions of a stoker boiler is higher than that of a fluidized bed boiler. Therefore, it is not known whether this same efficiency would coincide with a fluidized bed boiler with initial NO_x emissions that are less than those of modern stoker boilers.⁴⁶ Based on site-specific vendor data, the uncontrolled NO_x emissions of 0.20 lb/MMBtu would be expected to be reduced to 0.06 lb/MMBtu using a tail end SCR.

P&GPP evaluated the environmental, energy, and economic impacts of using a tail end SCR. No significant environmental impacts are expected from operation of a tail end SCR. Energy impacts include combustion of 31 MMscf per year of natural gas to reheat the flue gas as well as 10 MW of lost capacity split between direct electrical load and increased pressure drop across the system. Next, P&GPP evaluated the economic impacts of a tail end SCR. This evaluation resulted in an annualized cost effectiveness for a tail end SCR were estimated to be \$9,830 per ton of NO_x removed. Refer to detailed calculations included in Appendix D for more information on the energy and economic impacts.

P&GPP has determined that a tail end SCR system is not BACT based on the environmental, energy, and economic analyses. Beyond the consumption of significant additional fuel and worse heat rate, the annualized cost for the SCR is well beyond the range of cost effectiveness for BACT, and even more so when considering the very high incremental costs relative to other control devices as discussed later in this section (\$68,345 per additional ton of NO_x removed as compared to a SNCR). Therefore, the next most efficient control technology listed in Table 5-1, hot end SCR, was evaluated.

⁴⁵ In comments to Yellow Pine Energy Company on June 17, 2008, Georgia EPD states that, "EPD agrees that reheating flue gases with additional fuel would make the cost of control excessive and we believe that the impacts from the additional energy usage and emissions (from the additional fuel combustion) would be adverse impacts in this case."
<http://www.georgiaair.org/airpermit/downloads/permits/psd/dockets/yellowpine/epddocs/061708epdrequest.pdf>

⁴⁶ Abrams, Richard F. (Babcock Power Environmental, Inc.) and Kevin Toupin (Riley Power, Inc.). *Efficient and Low Emission Stoker Fired Biomass Boiler Technology in Today's Marketplace*. Worcester, MA: Babcock Power Environmental, Inc. March 2007. <http://www.babcockpower.com/pdf/t-200.pdf>

5.4.5.2. Hot End/High Dust SCR

Hot end, high dust SCR systems have been permitted and installed on boilers firing biomass or combined fuels; however, they have been primarily used on boilers firing natural gas, fuel oil, and coal. The primary issue associated with a hot end SCR involves the presence of other alkali metals and trace elements in the particulate matter of the flue gas that can chemically damage the catalyst, gradually neutralizing its ability to reduce NO_x. This chemical damage not only cuts the lifespan of the catalyst, but also increases the amount of ammonia slip. These alkali metals and trace elements include arsenic, sodium, potassium, and zinc. Sodium and potassium, both of which are present in fairly high concentrations in wood, are of particular concern for catalyst reactivity.

P&GPP is not aware of any CFB or BFB biomass boilers in the United States that are equipped with a high dust SCR. P&GPP is aware of four biomass-fired CFB or BFB boilers operating outside the United States that employ a SNCR/SCR hybrid technology.⁴⁷ One of the CFB boilers is located at Wien Energy's Simmering plant, in Vienna, Austria. Although this facility has been able to meet its permit limits, the SCR vendor, CERAM, is uncertain if the NO_x reduction is due to the SNCR portion or catalyst portion of the SCR. A second CFB boiler had been operated with a high dust SCR for NO_x control at Norrköpping Energi AB in Sweden. However, the high dust SCR had many issues; the primary problem was the high operating costs stemming from the need to have the catalyst washed off-line frequently due to chemical damage and plugging from the biomass/TDF fuels. The plant eventually elected to decommission the SCR and instead utilize an SNCR system for NO_x control. Since this change, the SNCR system has produced similar NO_x reductions as the SCR system, without the high maintenance costs and boiler downtime.⁴⁸

The two biomass-fired BFB boilers employing the hybrid SNCR/high dust SCR systems are located at the Cuijk Essent (Netherlands) and Stora Enso (Sweden) facilities. Both units have been successfully operated; however, the SCR reductions (beyond the SNCR reductions) have only been 5% and 22%, respectively. System outlet emissions have been equivalent to approximately 0.10 lb/MMBtu, much less than theoretically expected and very similar to the expected NO_x emissions achieved by the proposed P&GPP Biomass Cogeneration Boiler via usage of only an SNCR.

Despite real questions about the technical feasibility of a high dust SCR for this application, P&GPP has nonetheless assumed for the purposes of this economic analysis that a high dust SCR system is technically feasible and could achieve NO_x outlet emissions of 0.06 lb/MMBtu.

P&GPP evaluated the environmental, energy, and economic impacts of using a high dust SCR. No significant environmental impacts are expected from operation of a high dust SCR (although catalyst must be replaced and/or regenerated more frequently than a tail end SCR). Energy impacts are attributed to only the additional 5 MW of capacity associated with pressure drop across the SCR itself. Next, P&GPP evaluated the economic impacts of a high dust SCR. Based on cost calculations, as included in Appendix D, such a system is expected to have an annualized cost of \$9,346 per ton of

⁴⁷ The ammonia is injected sufficiently early in the unit such that SNCR reactions first occur, with unreacted ammonia continuing downstream to the catalyst and potentially further decreasing the NO_x levels. Thus, the hot SCR system is effectively an SNCR system followed by an SCR.

⁴⁸ The Metso data are from an email sent by Bob Denault (Metso Power) to Mark Sajer (Summit Energy Partners, LLC) on March 28, 2008. This document was contained in a response to EPD's comments, dated 6/17/2008, regarding Yellow Pine Energy Company's PSD permit application #17700. <http://www.georgiaair.org/airpermit/downloads/permits/psd/dockets/yellowpine/facilitydocs/080108ypresp-a4a7.pdf>

NO_x removed. Refer to detailed calculations included in Appendix D for more information on the energy and economic impacts.

P&GPP has determined that a high dust SCR is not BACT based on the environmental, energy, and economic analyses. While the loss of heat rate is only half that of the RSCR, the annualized cost for the SCR is well beyond the accepted range of cost effectiveness for BACT, particularly when considering the incremental costs relative to other control devices as discussed later in this section: \$63,830 per additional ton of NO_x removed as compared to a SNCR. In addition, there are real concerns regarding whether this technology is truly technically feasible. Therefore, the next most efficient control technology listed in Table 5-1, SNCR, is evaluated.

5.4.5.3. SNCR

SNCR has been successfully utilized and considered BACT on a number of fluidized bed biomass-fired boilers, according to RBL entries. SNCR systems are generally thought to have a NO_x reduction efficiency of up to 60%; however, for certain industries operating under ideal temperature and residence time, control efficiencies of up to 90 percent have been observed. A boiler vendor consulted for this project was willing to guarantee 62.5% control efficiency, equivalent to an NO_x emission limit of 0.075 lb/MMBtu.

P&GPP evaluated the environmental and energy impacts of using a SNCR. No significant environmental and energy impacts are expected from operation of a SNCR. It is anticipated that the SNCR cost effectiveness, cost per ton of NO_x removed, would be less than \$3,000 per ton of pollutant removed, which is considered acceptable.

P&GPP believes that a SNCR is BACT since it will have minimal environmental and energy impacts and is within the range of costs generally considered to be cost-effective.

5.4.6. Selection of BACT (Step 5)

Based on the previous analyses, P&GPP has determined that SNCR is BACT for the proposed Biomass Cogeneration Boiler. The environmental and energy impacts of the two SCR systems and the SNCR system are similar. However, the economic impacts of the two SCR systems are significantly higher than that of the SNCR for both annualized and incremental costs. Table 5-2 presents a summary of the economic impacts.

Between the negative energy impacts of the SCR technologies, the average cost effectiveness beyond the accepted range for BACT, and the very high incremental cost effectiveness of either SCR technology, P&GPP has determined that neither the tail end SCR or high dust SCR are BACT. Thus, SNCR coupled with proper boiler design (i.e., circulating fluidized bed) and combustion control has been selected as BACT for the proposed Biomass Cogeneration Boiler. The validity of this determination is also evidenced by the lack of biomass fluidized bed units using either type of SCR system.

TABLE 5-2. ANNUAL AND INCREMENTAL COSTS FOR SCRs AND SNCR

Control Device	Average Cost (\$/ton)	Additional Emissions Removed ¹ (tpy)	Additional Annual Cost ² (\$/yr)	Incremental Cost ³ (\$/ton)
Tail End SCR	9,830	68.13	4,656,435	68,345
High Dust SCR	9,346	68.13	4,348,793	63,830
SNCR	2,808	-	-	-

1. Additional NO_x removed by the SCR as compared to using a SNCR to achieve 0.075 lb/MMBtu outlet emissions.
2. Additional annual operating cost for the SCR being evaluated as compared to the SNCR.
3. Annual operating cost for the SCR divided by the additional emissions removed.

The emission levels determined to constitute BACT for biomass boilers with heat input capacities exceeding 250 MMBtu/hr within the last 10 years vary greatly (refer to the RBLC Search/Permit Review table in Appendix D). The most stringent limits are shown in Table 5-3 and were considered by P&GPP in determining the appropriate emission rate to propose as BACT for the Biomass Cogeneration Boiler. Limits for boilers employing SCR or RSCR were not considered further since a SCR was determined to be economically infeasible for the proposed P&GPP Biomass Cogeneration Boiler. P&GPP is going with the emission rate determined from the RBLC search using SNCR, 0.075 lb/MMBtu NO_x outlet emissions. The proposed averaging period for the proposed BACT emission limit is a 24-hour rolling average monitored by a continuous emissions monitoring system (CEMS).

5.5. BIOMASS COGENERATION BOILER - SO₂ BACT

5.5.1. Background on Pollutant Formation

SO₂ emissions result from the oxidation of sulfur in the fuel during the combustion process. Uncontrolled SO₂ emissions almost entirely depend upon the sulfur content of the fuel and are not dependent upon boiler properties such as size, burner design, or fuel grade. Almost all of the fuel sulfur released is in the form of SO₂. The 0.26 lb/MMBtu uncontrolled SO₂ emission rate is based on sulfur content calculations provided by the engineering firm, ESI Inc. of Tennessee, based on biomass available in the region.

TABLE 5-3. MOST STRINGENT RBLC ENTRIES FOR NO_x CONTROL

ID	State	Company/Facility	Boiler Type	Capacity (MMBtu/hr)	Permitted Fuels	Permit Date	Limit (lb/MMBtu)	Avg. Period	Control Type	Compliance Method	Note(s)
MA-02a	MA	RUSSELL BIOMASS	BFB	740	Clean Wood	12/30/2008	0.060	Unknown	SCR	CEMS	1
MA-02b	MA	RUSSELL BIOMASS	Stoker	740	Clean Wood	12/30/2008	0.060	Unknown	RSCR	CEMS	1
MA-03	MA	PIONEER RENEW ABLE ENERGY	Stoker	663	Wood	Application	0.060	Unknown	SCR	CEMS	1
MA-05	MA	PALMER RENEW ABLE ENERGY	Stoker	38 MW	Biomass	Application	0.060	Unknown	RSCR	CEMS	1
NH-05	NH	CONCORD STEAM CORPORATION	Stoker	305	Biomass, Natural Gas (startup)	2/27/2009	0.065	30-day	SCR	CEMS	1
NE-04	NE	ARCHER DANIELS MIDLAND, COLUMBUS	CFB	768	Coal, Biomass, Petcoke, TDF	Draft, 2008	0.07	30-day	SNCR	CEMS	2
CT-03	CT	WATERTOWN RENEW ABLE POWER	FB Gasification	436	Biomass, Natural Gas (startup)	Draft 2009	0.075	24-hour	SCR	CEMS	1
CT-02	CT	PLAINFIELD RENEW ABLE ENERGY	FB Gasification	523	Biomass, biodiesel	2008	0.075	30-day	SNCR	CEMS	1
ME-01	ME	BORALAX STRATTON ENERGY, INC.	FB	672	Wood, Oil	1/4/2005	0.075	Quarterly	Ecotube, RSCR	CEMS	3
NH-0013	NH	SCHILLER STATION, PUBLIC SERVICE OF NH	CFB	720	Wood, Coal	10/25/2004	0.075	24-hour	SNCR	CEMS	3
NH-02	NH	BRIDGEWATER POWER COMPANY	Stoker	250	Wood, Oil	9/12/2007	0.075	Quarterly	SNCR, RSCR	CEMS	3
NH-03	NH	WHITEFIELD POWER	Stoker	220	Wood	2004	0.075	Quarterly	RSCR	CEMS	3
VT-01	VT	BURLINGTON ELECTRIC DEPT, MCNEIL STATION	Stoker	750	Wood, Natural Gas, Oil	4/21/2008	0.075	Quarterly	RSCR	CEMS	3
OH-0307	OH	SOUTH POINT BIOMASS GENERATION	Stoker	318	Wood	4/4/2006	0.088	30-day	SCR	CEMS	4
GA-02	GA	YELLOW PINE ENERGY COMPANY	BFB	1,529	Biomass, TDF, Propane, Fuel Oil	5/15/2009	0.10	30-day	SNCR	CEMS	
MI-0386	MI	RIPLEY HEATING PLANT	CFB	205	Wood, Coal, Gas	5/12/2008	0.10	30-day	SNCR	CEMS	
TX-31	TX	NACOGDOCHES POWER PLANT, AMERICAN RENEWABLES	BFB	1,374	Biomass, Gas	3/1/2007	0.10	30-day	SNCR	CEMS	
VA-11	VA	MULTITRADE OF PITTSYLVANIA COUNTY (DOMINION)	Stoker	373	Biomass	1/1/2003	0.10	30-day	SNCR	CEMS	5
NM-03	NM	WESTERN WATER & POWER - ESTANCIA BASIN BIOMASS	BFB	483	Biomass	Draft, 2007	0.11	30-day	SNCR	CEMS	4
WA-0327	WA	SKAGIT COUNTY LUMBER MILL	Stoker	430	Biomass	12/12/2005	0.13	24-hour	SNCR	CEMS	
FL-0257	FL	CLEWISTON SUGAR MILL AND REFINERY	Unknown	936	Bagasse, Diesel	11/18/2003	0.14	30-day	SNCR	Unknown	

1. LAER limit.
2. Limit excludes startup periods.
3. Voluntary limit, not a BACT limit.
4. Based on lb/hr limit and maximum permitted capacity.
5. Minimum of 50% control required.

5.5.2. Identification of Potential Control Techniques (Step 1)

Candidate control options identified from the RBLC search (refer to discussion in Section 5.4.1), permit review, and literature review included those classified as both pollution prevention and pollution reduction techniques. SO₂ pollution prevention and reduction options include:

- Limestone Injection
- Wet Flue Gas Desulfurization (WFGD)/Wet Scrubber
- Dry FGD (DFGD)/Spray Dryer with Baghouse
- Duct Sorbent Injection (DSI)
- Good Design and Operating Practices

These control technologies are briefly discussed in the following sections.

5.5.2.1. Limestone Injection

Fluidized bed boilers typically use sand or similar materials for the bed material. Limestone can be added to the bed material as an “in-situ” SO₂ control. This form of control works on the basis of a several chemical reactions that work in series. First, the limestone calcines ($\text{CaCO}_3 \rightarrow \text{CaO} + \text{CO}_2$), allowing for the lime, or calcium oxide (CaO), to react with SO₂ and O₂ to form calcium sulfate, CaSO₄. The calcium sulfate is a solid that is captured by the particulate control, resulting in a reduction of SO₂ emissions.

5.5.2.2. WFGD/Wet Scrubber

In a WFGD or wet scrubber system, a liquid alkaline sorbent is sprayed into the flue gas in a vessel to adsorb SO₂ from the flue gas. The SO₂ reacts with the alkaline liquid and is removed in solution as a liquid waste. Additional sorbent solution is added to the recirculating sorbent solution to compensate for the quantity that reacts with SO₂.⁴⁹ Typically, large quantities of liquid waste are disposed of by wastewater treatment holding ponds. Control efficiencies of up to 98% are possible with applications with sufficiently high SO₂ concentration. Since woody biomass has less sulfur content than most fuels, 95% control efficiency for this technology was considered in the BACT impacts evaluation.⁵⁰

5.5.2.3. DFGD/Spray Dryer with Baghouse

This technique, also known as “dry scrubbing,” requires installation of a spray dryer and a baghouse. An alkaline slurry is injected by a spray dryer into the flue gas in the form of fine droplets under well controlled conditions such that the droplets will absorb SO₂ from the flue gas and then become dry particles because of the evaporation of water. The dry particles are captured by the baghouse downstream of the dryer. The captured particles are then removed from the system and disposed. The advantages of this system include a dry waste product and simpler process control.⁵¹

⁴⁹ U.S. EPA, CATC Fact Sheet for FGD, EPA-452/F-03-034. <http://www.epa.gov/ttn/catc/dir1/ffdg.pdf>

⁵⁰ U.S. EPA, CATC Fact Sheet for FGD, EPA-452/F-03-034. <http://www.epa.gov/ttn/catc/dir1/ffdg.pdf>

⁵¹ Kitto, J.B. *Air Pollution Control for Industrial Boiler Systems*. Barberton, OH: Babcock & Wilcox. November 1996. <http://www.babcock.com/library/pdf/BR-1624.pdf>

Dry scrubbing technology is capable of achieving over 90% control in certain applications.⁵² Given the additional scrubbing effect of alkaline wood ash, a control efficiency of approximately 92% was used.

5.5.2.4. Duct Sorbent Injection (DSI)

DSI systems are typically placed in between the air heater outlet and particulate control inlet, where the sorbent is injected into the flue gas either dry or damp. A humidifier can then be used to cool the flue gas through evaporation to approach the adiabatic saturation temperature of the flue gas. This creates an atmosphere that allows for this technology to be most effective. Additionally, a fabric filter is instrumental in achieving SO₂ removal due to the intimate contact between the flue gases and sorbent in the filter cake.⁵³

5.5.2.5. Good Design and Operating Practices

Good design and operating practices imply that the boiler is operated within parameters that, without significant control technology, allow the equipment to operate as efficiently as possible. In addition to minimizing SO₂ emissions through good operating practices, this control option includes combustion of biomass fuel which has inherently low sulfur content.

5.5.3. Elimination of Technically Infeasible Control Options (Step 2)

After the identification of control options, the second step in the BACT assessment is to eliminate technically infeasible options. A control option is eliminated from consideration if there are process-specific conditions that would prohibit the implementation of the control or if the highest control efficiency of the option would result in an emission level that is higher than any applicable regulatory limits. Additionally PSD applicants routinely eliminate control options in this step in cases in which a control alternative is either no more effective than the proposed control alternative because additional consideration of such controls provides no practical benefit. Two control technologies are eliminated in this step on this basis.

The following control technologies have been considered technically infeasible for the proposed Biomass Cogeneration Boiler.

5.5.3.1. Limestone Injection

Limestone injection in CFB boilers is technically feasible; however, it is less effective than the proposed control alternative of dry sorbent injection.⁵⁴ Accordingly, additional consideration of limestone injection is unwarranted.

5.5.3.2. Spray Dryer with Baghouse

Spray Dryer with Baghouse control is technically feasible on CFB Boilers; however, it is equivalent in control efficiency to the proposed control alternative of dry sorbent injection.⁵⁵ Accordingly, additional consideration of spray dryer with baghouse is unwarranted.

⁵² Sewell, Melissa; Dickerman, Jim. *Dry sorbent Injection Options for Controlling Emissions of HCl and Related Acid Gases*. Lhoist North America.

⁵³ Ibid.

⁵⁴ U.S. EPA, CATC Fact Sheet for FGD, EPA-452/F-03-034. <http://www.epa.gov/ttn/catc/dir1/ffdg.pdf>

⁵⁵ Sewell, Melissa; Dickerman, Jim. *Dry sorbent Injection Options for Controlling Emissions of HCl and Related Acid Gases*. Lhoist North America.

5.5.4. Rank of Remaining Control Technologies (Step 3)

The third of the five steps in the top-down BACT assessment procedure is to rank technically feasible control technologies by control effectiveness. The remaining control technologies, ranked by their control effectiveness, are presented in Table 5-4.

TABLE 5-4. REMAINING SO₂ CONTROL TECHNOLOGIES

Rank	Control Technology	Expected Emissions
1	WFGD/Wet Scrubber	0.013 lb/MMBtu
2	Duct Sorbent Injection	0.020 lb/MMBtu
3	Good Design and Operating Practices	0.26 lb/MMBtu

5.5.5. Evaluation of Most Stringent Controls (Step 4)

The fourth of the five steps in the top-down BACT assessment procedure is to evaluate the most effective control and document the results. This has been performed for each remaining control technology on the basis of economic, energy, and environmental considerations, and is described below.

5.5.5.1. WFGD/Wet Scrubber

New wet scrubber systems are anticipated to reduce SO₂ outlet emissions from the proposed Biomass Cogeneration Boiler from 0.26 lb/MMBtu (worst-case fuel) to approximately 0.013 lb/MMBtu. The capital and overall costs of a wet scrubber on a fluidized bed boiler are expected to be quite high relative to other sulfur control options. Additionally, biomass-fired boilers have inherently low SO₂ emissions due to the low sulfur content of the fuel. For this reason, a wet scrubber system will not be able to provide as high a reduction efficiency as those that are achieved for high-sulfur, coal-fired boilers since firing the biomass fuel results in low uncontrolled SO₂ emissions of 0.26 lb/MMBtu.

P&GPP evaluated the environmental, energy, and economic impacts of a wet scrubber system. The environmental impacts associated with the wet scrubber include needing approximately 55 million gallons per year of water for the alkaline liquid, treating of the wastewater, and increased solid waste disposal of from the waste generated from the caustic and SO₂ reaction. Energy impacts associated with operation of the scrubber system itself will require 14 MW of capacity. To evaluate the economic impacts, P&GPP calculated the annualized cost of operating a wet scrubber system. Based on cost calculations included in Appendix D (which do not include costs associated with treatment of the waste scrubbant liquid), a wet scrubber system would be expected to have annual costs of more than \$12,807 of SO₂ removed, far beyond an acceptable cost effectiveness.

Based on the environmental, energy, and economic analyses, P&GPP determined that a wet scrubber is not BACT for reducing SO₂ emissions from the proposed Biomass Cogeneration Boiler. Thus, P&GPP proceeded with evaluating the next most efficient control option presented in Table 5-4, dry sorbent injection.

5.5.5.2. Duct Sorbent Injection

A DSI system, using dry or slightly damp alkaline sorbent in conjunction with a baghouse, has significant economic benefits when compared with the WFGD and DFGD systems, along with offering outlet SO₂ emissions of 0.01 lb/MMBtu, equivalent to DFGD and in the same range as WFGD, due to the low uncontrolled SO₂ levels in the flue gas.

Environmental impacts for DSI are not expected to be significant. While additional solid waste is generated, no additional water is used nor wastewater generated. The energy impacts associated with DSI are only 2 MW of capacity needed to operate the DSI system. Economic impacts are reasonable range for cost effectiveness for SO₂, with an annual cost of less than \$2,854 of SO₂ removed. Refer to Appendix D for calculation details.

Based on the environmental, energy, and economic analyses, P&GPP determined that DSI is BACT for the proposed Biomass Cogeneration Boiler. This technology represents a high SO₂ removal while remaining cost effective and minimizing environmental and energy impacts.

5.5.6. Selection of BACT (Step 5)

Based on the previous analyses, P&GPP has determined that DSI is BACT for the proposed Biomass Cogeneration Boiler. While energy impacts are similar, the environmental and economic impacts of the wet scrubber and spray dryer systems are significantly higher than those of the DSI system. Table 5-5 presents a summary of the economic impacts.

TABLE 5-5. ANNUAL COSTS FOR SO₂ CONTROL DEVICES

Control Device	Average Cost (\$/ton)
Wet Scrubber	12,807
DSI	2,854

Usage of DSI is determined as BACT for the proposed Biomass Cogeneration Boiler.

The emission levels determined to constitute BACT for biomass fluidized bed boilers with heat input capacities exceeding 250 MMBtu/hr within the last 10 years vary greatly (refer to the RBLC Search/Permit Review table in Appendix D). The most stringent limits are shown in Table 5-6 and were considered by P&GPP in determining the appropriate emission rate as BACT for the Biomass Cogeneration Boiler.

TABLE 5-6. MOST STRINGENT RBLC ENTRIES FOR SO₂ CONTROL

ID	State	Company/Facility	Boiler Type	Capacity (MMBtu/hr)	Permitted Fuels	Permit Date	Limit (lb/MMBtu)	Avg. Period	Control Type	Compliance Method	Note(s)
VT-01	VT	BURLINGTON ELECTRIC DEPT, MCNEIL STATION	Stoker	750	Wood, Natural Gas, Oil	4/21/2008	0.0083	Annual	Good Combustion Practices	Fuel Records	
GA-02	GA	YELLOW PINE ENERGY COMPANY	BFB	1529	Biomass, TDF, Propane, Fuel Oil	5/15/2009	0.014	30-day	Dry Scrubber	CEMS	
LA-0201	LA	WEYERHAEUSER - RED RIVER MILL	Unknown	940	Wood, Sludge, Recycle Fiber, Gas	5/24/2006	0.015	3-hour	Good Combustion Practices	Stack Test	
VA-11	VA	MULTITRADE OF PITTSYLVANIA COUNTY	Stoker	373.3	Biomass	1/1/2003	0.016	30-day	Good Combustion Practices	CEMS	
NM-03	NM	WESTERN WATER & POWER - ESTANCIA BASIN BIOMASS	BFB	483	Biomass	Draft, 2007	0.019	30-day	Good Combustion Practices	Stack Test	1
NH-0013	NH	SCHILLER STATION, PUBLIC SERVICE OF NH	CFB	720	Wood, Coal	10/25/2004	0.02	24-hour	Lime Injection	CEMS	2
MA-05	MA	PALMER RENEWABLE ENERGY	Stoker	38 MW	Biomass	Application	0.02	Unknown	Scrubber	Unknown	2
NC-0092	NC	RIEGELWOOD MILL, INTERNATIONAL PAPER CO.	Unknown	600	Coal, Wood, Sludge, Fuel Oil	5/10/2001	0.024	3-hour	Venturi scrubber	Stack Test	3
MA-02a	MA	RUSSELL BIOMASS	BFB	740	Clean Wood	12/30/2008	0.025	Unknown	Fuel selection	CEMS	
MA-02b	MA	RUSSELL BIOMASS	Stoker	740	Clean Wood	12/30/2008	0.025	Unknown	Fuel selection	CEMS	
MA-03	MA	PIONEER RENEWABLE ENERGY	Stoker	663	Wood	Application	0.025	Unknown	Wood ash alkalinity	Unknown	
WA-0327	WA	SKAGIT COUNTY LUMBER MILL	Stoker	430	Biomass	12/12/2005	0.025	3-hour	Good Combustion Practices	Stack Tests	
CT-03	CT	WATERTOWN RENEWABLE POWER	FB Gasification	436	Biomass, Natural Gas (startup)	Draft 2009	0.025	3-hour	DSI	CEMS	

1. Based on lb/hr limit and maximum permitted capacity.

2. Not a BACT limit.

3. Limit is for biomass combustion.

As shown in Table 5-6, SO₂ emission rates for biomass boilers vary due to fuel sulfur content, control methodology employed, and averaging period. P&GPP has determined that a BACT limit of 0.02 lb/MMBtu on a 30-day rolling averaging period is appropriate given the range of sulfur contents in the biomass fuels proposed for the Biomass Cogeneration Boiler and based on expected vendor guarantees. The BACT limit for SO₂ is for normal operation (i.e., not including startup). This limit is more stringent than any other recent SO₂ BACT determination based on the proposed averaging period, since the McNeil Station has both a longer averaging period (annual vs. 30-day) and a less stringent compliance method (fuel recordkeeping). Compliance with this limit will be achieved via usage of DSI and low sulfur fuels (natural gas); compliance will be evaluated via a CEMS.

5.6. BIOMASS COGENERATION BOILER - PM/PM₁₀/PM_{2.5} BACT

This section identifies control options for the reduction of filterable PM. Although PSD permitting is also required for PM₁₀ and PM_{2.5}, those options used to reduce PM will also reduce PM₁₀ and PM_{2.5}. Additionally, a total PM (filterable plus condensable) limit is discussed. It should be noted that the proposed BACT emission levels assumed that all size fractions of particulate matter (PM/PM₁₀/PM_{2.5}) are equivalent due to the fact that essentially all filterable particulate matter has been controlled to a size fraction of PM_{2.5} or less and all condensable particulate matter can be assumed to consist of size PM_{2.5} or less.

5.6.1. Background on Pollutant Formation

Filterable PM emissions from Biomass Cogeneration Boiler combustion include the ash from the fuel combustion, byproducts of sorbent injection, as well as any unburned carbon resulting from incomplete combustion. In contrast to filterable particulate, condensable particulate is less understood, and the quantities are less certain. A portion of condensable particulate results from sulfur and chlorine in the fuel and their resultant acid gases. Other condensable particulate can form from a portion of NO_x being oxidized to NO₃ (acidic) as well as from high molecular weight organics. The compounds that form condensable particulate are controlled via other pollutant BACT – SO₂ BACT for acid gases and CO BACT for high molecular weight organics. Thus, control options for condensable particulate are not discussed in this section, though a BACT emission rate for condensable PM is included.

5.6.2. Identification of Potential Control Techniques (Step 1)

Candidate control options for reducing filterable PM were identified from the RBL search (refer to discussion in Section 5.4.1) and the literature review. Filterable PM reduction options, which may be utilized in series, include:

- Electrostatic Precipitator (ESP)
- Baghouse (Fabric Filter)
- Cyclone/Multiclone
- Venturi Scrubber
- Good Design and Operating Practices

These control technologies are briefly discussed in the following sections.

5.6.2.1. Electrostatic Precipitator (ESP)

An ESP removes particles from an air stream by electrically charging the particles then passing them through a force field that causes them to migrate to an oppositely charged collector plate. After the particles are collected, the plates are knocked (“rapped”), and the accumulated particles fall into a collection hopper at the bottom of the ESP. The collection efficiency of an ESP depends on particle diameter, electrical field strength, gas flow rate, and plate dimensions. An ESP can be designed for either dry or wet applications.⁵⁶

5.6.2.2. Baghouse (Fabric Filter)

A baghouse consists of several fabric filters, typically configured in long, vertically suspended sock-like configurations. Dirty gas enters from one side, often from the outside of the bag, passing through the filter media and forming a particulate cake. The cake is removed by shaking or pulsing the fabric, which loosens the cake from the filter, allowing it to fall into a bin at the bottom of the baghouse. The air cleaning process stops once the pressure drop across the filter reaches an economically unacceptable level. Typically, the trade-off to frequent cleaning and maintaining lower pressure drops is the wear and tear on the bags produced in the cleaning process.⁵⁷

5.6.2.3. Cyclone Separators

Cyclone separators, which can be arranged in series as a multiclone, remove solids from the air stream by application of centrifugal force. Typically, the particle-laden gas enters the top of the cyclone tangentially to the barrel and spins inside the device. Because of the shape of the device, the gas turns and forms a vortex in the center of the device as it moves upward to the exit duct. The particles are removed by centrifugal force, which drives them to the wall of the collector where they fall to the bottom due to gravity. Cyclones are efficient in removing larger, denser particles but are not as effective for fine particle removal (less than 10 µm diameter).⁵⁸

5.6.2.4. Venturi Scrubber

Venturi scrubbers intercept dust particles using droplets of liquid (usually water). The larger, particle-enclosing water droplets are separated from the remaining droplets by gravity. The solid particulates are then separated from the water. The waste water must be properly treated.⁵⁹

5.6.2.5. Good Design and Operating Practices

Good design and operating practices imply that the boiler is operated within parameters that, without significant control technology, allow the equipment to operate as efficiently as possible.

5.6.3. Elimination of Technically Infeasible Control Options (Step 2)

All potential control technologies identified in Section 5.6.2 are considered feasible for removing filterable PM.

⁵⁶ Kitto, J.B. *Air Pollution Control for Industrial Boiler Systems*. Barberton, OH: Babcock & Wilcox. November 1996. <http://www.babcock.com/library/pdf/BR-1624.pdf>

⁵⁷ Ibid.

⁵⁸ Ibid.

⁵⁹ U.S. EPA, CATC Fact Sheet for Venturi Scrubbers, EPA-452/F-03-017. <http://www.epa.gov/ttn/catc/dir1/fventuri.pdf>

5.6.4. Rank of Remaining Control Technologies (Step 3)

The third of the five steps in the top-down BACT assessment procedure is to rank technically feasible control technologies by control effectiveness. The remaining control technologies are presented in Table 5-7.

TABLE 5-7. REMAINING PM/PM₁₀/PM_{2.5} CONTROL TECHNOLOGIES

Rank	Control Technology	Expected Emissions
1	Fabric Filter	0.0098 lb/MMBtu, filterable
2	ESP	0.015 lb/MMBtu, filterable
3	Venturi Scrubber	0.040 lb/MMBtu, filterable
4	Cyclone/Multicyclone	0.10 lb/MMBtu, filterable
5	Good Design and Operating Practices	1.28 lb/MMBtu, filterable

5.6.5. Evaluation of Most Stringent Controls (Step 4)

The fourth of the five steps in the top-down BACT assessment procedure is to evaluate the most effective control and document the results. This has been performed for each remaining control technology on the basis of economic, energy, and environmental considerations, and is described below.

P&GPP has proposed to install a baghouse (fabric filter) to reduce filterable PM emissions from the boiler. As this device is ranked as the most efficient control option in Table 5-7, P&GPP has determined that the proposed baghouse is BACT for the Biomass Cogeneration Boiler.

5.6.6. Selection of BACT (Step 5)

Based on the analysis described above, a baghouse is proposed as the BACT control for the biomass-fired boiler for filterable particulate. In addition, the baghouse is an integral part of the DSI system used for acid gas/condensable particulate control.

The proposed BACT level of 0.0098 lb/MMBtu for filterable particulate matter is equal to the Boiler NESHAP Maximum Achievable Control Technology (MACT) limit for new sources. Since the new source MACT limit for fluid bed biomass sources was established in 2013 and required to be equivalent to the best performing source in the country, the proposed BACT is presumed to be based on the lowest achievable emission rate possible for filterable particulate matter. Condensable particulate matter is also formed during combustion of biomass. Accordingly, a combined PM/PM₁₀/PM_{2.5} BACT emission level of 0.0268 lb/MMBtu value is proposed for this project. The proposed averaging period for the proposed BACT emission limit will be a 3-hour averaging period with compliance based on stack testing. Continuous compliance will be monitored in accordance with the MACT, using either a bag leak detection system or a continuous opacity monitoring system (COMS).

5.7. BIOMASS COGENERATION BOILER - CO AND VOC BACT

5.7.1. Background on Pollutant Formation

CO and VOC emissions from biomass boilers are a by-product of incomplete combustion. CO is a by-product of the combustion process in which carbon is not fully oxidized to CO₂. Likewise, VOC is emitted when the carbonaceous matter in the fuel is not converted to CO₂ or CO. Control of both species involves forcing the oxidation of carbon to CO₂. Conditions leading to incomplete combustion include the following: insufficient oxygen availability, poor fuel/air mixing, reduced combustion temperature, reduced combustion gas residence time, and load reduction. In addition, combustion modifications taken to reduce NO_x emissions may result in increased CO emissions.

5.7.2. Identification of Potential Control Techniques (Step 1)

Candidate control options identified from the RBLC search and the literature review include those classified as pollution reduction techniques. CO and VOC reduction options include:

- Regenerative Oxidation Catalyst
- Good Design and Operating Practices

These control technologies are briefly discussed in the following sections.

5.7.2.1. Oxidation Catalyst

Regenerative catalytic oxidation (RCO) technology is widely used in the reduction of VOC emissions, and concurrently, to reduce CO emissions. It is the only oxidation technology evaluated because it requires only moderate reheating to a minimum temperature of 450 °F. Furthermore, RCOs can achieve a high thermal efficiency because they utilize a ceramic bed to recapture the heat of the stream exiting the combustion zone. Particulate control must be placed upstream of an RCO. Even with highly efficient TSP/PM₁₀ control, there is the risk of catalyst blinding/poisoning and catalyst life guarantees are relatively short.

5.7.2.2. Good Design and Operating Practices

A properly designed and operated power boiler acts as an oxidizer. Ensuring that the temperature and oxygen availability are adequate for complete combustion minimizes VOC and CO formation. This technique includes continued operation of the boiler at the appropriate oxygen range and furnace bed temperature.

5.7.3. Elimination of Technically Infeasible Control Options (Step 2)

After the identification of control options, the second step in the BACT assessment is to eliminate technically infeasible options. A control option is eliminated from consideration if there are process-specific conditions that would prohibit the implementation of the control or if the highest control efficiency of the option would result in an emission level that is higher than any applicable regulatory limits. Both previously identified control technologies are feasible.

5.7.4. Rank of Remaining Control Technologies (Step 3)

The third of the five steps in the top-down BACT assessment procedure is to rank technically feasible control technologies by control effectiveness. The remaining control technologies are presented in Table 5-9.

TABLE 5-9. REMAINING CONTROL TECHNOLOGIES

Rank	Control Technology	Expected CO Emissions	Expected VOC Emissions
1	Regenerative Oxidation Catalyst	0.015 lb/MMBtu	0.002 lb/MMBtu
2	Good Design and Operating Practices	0.10 lb/MMBtu	0.007 lb/MMBtu

5.7.5. Evaluation of Most Stringent Controls (Step 4)

The fourth of the five steps in the top-down BACT assessment procedure is to evaluate the most effective control and document the results. This has been performed for the remaining control technology on the basis of economic, energy, and environmental considerations, and is described below.

5.7.5.1. Regenerative Oxidation Catalyst

The oxidation catalyst must be installed downstream of the particulate control device to ensure that the catalyst is not chemically damaged. However, significant auxiliary fuel input will be required to raise the temperature of the flue gas. A regenerative oxidation catalyst system would be expected to reduce CO emissions from the proposed Biomass Cogeneration Boiler to 0.015 lb/MMBtu and VOC to 0.002 lb/MMBtu.

P&GPP evaluated the environmental, energy, and economic impacts of the no reheat and reheat required oxidation catalyst scenarios. Energy impacts include combustion of 305 MMscf of natural gas to reheat the flue gas as well as 6.3 MW of capacity associated with pressure drop operation from the oxidation catalyst.

Next, P&GPP evaluated the economic impacts of the oxidation catalyst. Based on scaled vendor quotes for total capital costs and OAQPS Manual equations, the annualized costs for a stand-alone oxidation catalyst system would be expected to be more than \$12,912 per ton of CO removed and \$223,991 per ton of VOC removed. The average cost effectiveness is very high for CO, which has far lower environmental impact than SO₂, NO_x, or PM/PM₁₀. Thus, even \$12,912 value is beyond the accepted range of cost effectiveness.

P&GPP has determined that an oxidation catalyst is not BACT based on the environmental, energy, and economic analyses and P&GPP proceeded with evaluating the next most efficient control option presented in Table 5-9.

5.7.5.2. Good Design and Operating Practices

The only remaining technology is good design and operating practices, a logical option since a properly designed and operated fluidized bed boiler minimizes CO and VOC formation. This is done by ensuring that the boiler temperature and oxygen availability are adequate for complete combustion. Good design and operating practices is considered BACT for CO and VOC for the proposed boiler.

5.7.6. Selection of BACT (Step 5)

Good design and operating practices to achieve minimum emissions of CO is determined as the BACT control for the proposed boiler. The emission levels determined to constitute BACT for biomass fluidized bed boilers with heat input capacities exceeding 250 MMBtu/hr within recent history vary greatly (refer to the RBLC Search/Permit Review table in Appendix D). The most stringent limits are shown in Table 5-10 for CO and 5-11 for VOC and were considered by P&GPP in determining the appropriate emission rates to propose as BACT for the Biomass Cogeneration Boiler.

As seen from Table 5-10 and Table D-11, CO and VOC emission rates for biomass boilers vary based on a few major factors. Primarily, the amount of CO and VOC emissions is inversely related to the amount of NO_x emissions. This is due to the basic principles of NO_x and CO formation in combustion. In general, incomplete combustion leads to increased CO formation, while any amount of excess oxygen, which is needed for complete combustion, allows for the fuel-bound nitrogen to react with the oxygen to form fuel NO_x. P&GPP has determined that a limit of 0.10 lb/MMBtu on a 30-day rolling average for CO (as measured by a CEMS) and a limit of 0.007 lb/MMBtu for VOC is BACT for the proposed boiler. This limit is among the lowest limits shown in Table 5-10 and 5-11 and will be achieved without an oxidation catalyst.

5.8. BIOMASS STORAGE PILE - PM, PM₁₀, PM_{2.5}, VOC BACT

The following section identifies and selects the control technologies to be considered BACT for the biomass storage pile. The PM/PM₁₀/PM_{2.5} emissions from the storage pile are considered fugitive source emissions. Non-fugitive sources are those that vent through a stack, vent, or other functionally equivalent opening. Fugitive emission sources are converted to non-fugitive sources by enclosing the area and exhausting through a stack or functionally equivalent opening.

Emissions from the biomass storage pile result from the breakdown of solids into fine particulates that become airborne. This process, also known as “dusting,” potentially could result from wind erosion from the biomass storage pile. Emissions from the biomass storage pile are kept to insignificant levels due to the inherent moisture content of the biomass. Proposed emission levels are presented in Appendix B.

VOC emissions from the storage pile are considered fugitive emissions and add on emission controls are not practicable. There is no way to operate this emission source in ways to reduce emissions (e.g. Good Operating Practices) that would reduce emissions. Therefore, no control is proposed for VOC emissions from the storage pile.

5.9. MATERIAL STORAGE SILOS - PM, PM₁₀, PM_{2.5} BACT

This section identifies control options for the reduction of PM/PM₁₀/PM_{2.5} from the Sorbent Storage Silo and Fly Ash Storage Silo. PM/PM₁₀/PM_{2.5} emissions from these sources form in various ways, most notably from the breakdown of solids into fine particulates that become airborne. This effect is exacerbated by the amount of shifting that comes with the throughput of the materials. Emissions can be minimized through the usage of fabric filtration systems (baghouses, bin vent filters) and/or good operating practices.

Fabric filtration systems are the most effective technology for reducing emissions and operate by having particulate-laden exhaust enter from one side and pass through the filter media, which forms a particulate cake. The air cleaning process stops once the pressure drop across the filter reaches an economically unacceptable level. Typically, the trade-off to frequent cleaning and maintaining lower pressure drops is the wear and tear on the bags produced in the cleaning process.

P&GPP conducted a review of the RBLC to determine what control techniques have been employed to reduce filterable PM emissions from the storage silos. Table 5-15 show the most stringent emission limits and control techniques for ash and lime silos. Control for sand silos is expected to be similar to the techniques and grain loadings considered BACT for the ash and lime silos.

For the Sorbent Storage Silo and Fly Ash Storage Silo, P&GPP proposes to utilize fabric filtration systems to reduce outlet PM/PM₁₀/PM_{2.5} emissions to 0.005 gr/cf. In all instances, good operating procedures will be used to minimize the formation of PM/PM₁₀/PM_{2.5} from these areas.

5.10. COOLING TOWER - PM, PM₁₀, PM_{2.5} BACT

The multi-cell Cooling Tower will operate as part of the heat rejection process by circulating water through the surface condenser and using a mechanically induced draft to reject the heat from the cooling water to the environment, primarily through evaporation of a portion of the cooling water. In this process, a very small portion of the cooling water may be carried to the ambient air in liquid form. This is referred to as “drift loss” and can contain a small amount of mineral material, which is present in the cooling water. This will represent a very small source of PM/PM₁₀/PM_{2.5} at the P&GPP.

A search of the RBLC was done for potential control technologies for Cooling Towers. As shown in Table 5-16, the only control technology identified for the reduction of PM/PM₁₀/PM_{2.5} from Cooling Towers are drift eliminators. Drift eliminators are designed to capture as many of the droplets at the exit of the Cooling Tower as possible. By capturing these droplets, the amount of mineral material (in the form of PM/PM₁₀/PM_{2.5}) carried out into the ambient environment is reduced. This is accomplished by placing objects of various geometric configurations at the exit of the cooling towers. By forcing the exhaust to quickly change directions, the inertia of the droplets causes them to collide with the drift eliminators, in which the surface tension acts to keep the droplets on the surface of the drift eliminators. Gravity then pulls the droplets back down to the cooling tower basin.

TABLE 5-10. MOST STRINGENT RBLC ENTRIES FOR CO CONTROL

ID	State	Company/Facility	Boiler Type	Capacity (MMBtu/hr)	Permitted Fuels	Permit Date	Limit (lb/MMBtu)	Avg. Period	Control Type	Compliance Method	Note(s)
MA-02a	MA	RUSSELL BIOMASS	BFB	740	Clean Wood	12/30/2008	0.075	Unknown	Good Combustion Practices	CEMS	
MA-02b	MA	RUSSELL BIOMASS	Stoker	740	Clean Wood	12/30/2008	0.075	Unknown	Oxidation Catalyst	CEMS	1
MA-03	MA	PIONEER RENEWABLE ENERGY	Stoker	663	Wood	Application	0.075	Unknown	Oxidation Catalyst	CEMS	1
MA-05	MA	PALMER RENEWABLE ENERGY	Stoker	38 MW	Biomass	Application	0.075	Unknown	Oxidation Catalyst	CEMS	1
CT-03	CT	WATERTOWN RENEWABLE POWER	FB Gasification	436	Biomass, Natural Gas (startup)	Draft 2009	0.10	8-hour	Good Combustion Practices	CEMS	
NE-04	NE	ARCHER DANIELS MIDLAND, COLUMBUS	CFB	768	Coal, Biomass, Petcoke, TDF	Draft, 2008	0.10	30-day	Good Combustion Practices	CEMS	
NH-0013	NH	SCHILLER STATION, PUBLIC SERVICE OF NH	CFB	720	Wood, Coal	10/25/2004	0.10	24-hour	CFB Design	CEMS	
OH-0286	OH	AKRON THERMAL ENERGY CORPORATION	Grate	180	Wood, Tires, Gas	8/12/2008	0.10	annual	Good Combustion Practices	Fuel Records	2, 3
OH-0307	OH	SOUTH POINT BIOMASS GENERATION	Stoker	318	Wood	4/4/2006	0.10	30-day	Oxidation Catalyst	CEMS	
NM-03	NM	WESTERN WATER & POWER - ESTANCIA BASIN BIOMASS	BFB	483	Biomass	Draft, 2007	0.10	30-day	Good Combustion Practices	CEMS	3
CT-02	CT	PLAINFIELD RENEWABLE ENERGY	FB Gasification	523.1	Biomass, biodiesel	2008	0.105	30-day	Good Combustion Practices	CEMS	
GA-02	GA	YELLOW PINE ENERGY COMPANY	BFB	1529	Biomass, TDF, Propane, Fuel Oil	5/15/2009	0.149	30-day	Good Combustion Practices	CEMS	4
GA-09	GA	PLANT CARL, GREEN ENERGY PARTNERS	BFB	400	Biomass, Oil/Grease/Fat, Biodiesel, Chicken Litter	7/29/2008	0.149	30-day	Oxidation Catalyst	CEMS	4
TX-31	TX	NACOGDOCHES POWER PLANT, AMERICAN	BFB	1374	Biomass, Gas	3/1/2007	0.15	30-day	Good Combustion Practices	CEMS	
IA-0083	IA	ROQUETTE AMERICA, INC.	CFB	996	Coal, Petcoke, Biomass, TDF	8/16/2006	0.154	24-hour	Good Combustion Practices	CEMS	
IA-0095	IA	TATE & LYLE INGREDIENTS AMERICAS, INC.	Unknown	200	Corn Fibers, Gas, Biogas, Process Gas	9/19/2008	0.17	30-day	Good Combustion Practices	CEMS	4
MI-0386	MI	RIPLEY HEATING PLANT	CFB	205	Wood, Coal, Gas	5/12/2008	0.17	3-hour	Good Combustion Practices	Stack Test	

1. Part of an RSCR system.

2. Not a BACT limit.

3. Based on lb/hr limit and maximum permitted capacity.

4. Case-by-case MACT limit

TABLE 5-11. MOST STRINGENT RBLC ENTRIES FOR VOC CONTROL

ID	State	Company/Facility	Boiler Type	Capacity (MMBtu/hr)	Permitted Fuels	Permit Date	Limit (lb/MMBtu)	Avg. Period	Control Type	Compliance Method	Note(s)
OH-0286	OH	AKRON THERMAL ENERGY CORPORATION	Grate	180	Wood, Tires, Gas	8/12/2008	0.002	3-hour	Good Combustion Practices	Fuel Records	1, 2
LA-0190	LA	GEORGIA-PACIFIC - PORT HUDSON	CFB	Unknown	Wood, Sludge, Petcoke, Coal, Gas, Paper, Bagasse	8/22/2005	0.005	annual	Good Combustion Practices	None	1, 3
NH-0013	NH	SCHILLER STATION, PUBLIC SERVICE OF NH	CFB	720	Wood, Coal	10/25/2004	0.005	24-hour	Good Combustion Practices	None	1
ME-0021	ME	S.D. WARREN CO. - SKOWHEGAN, ME	Unknown	1300	Wood, Sludge, Oil, TDF, Paper, NCG	11/27/2001	0.007	3-hour	Good Combustion Practices	None	
NE-04	NE	ARCHER DANIELS MIDLAND, COLUMBUS	CFB	768	Coal, Biomass, Petcoke, TDF	Draft, 2008	0.007	3-hour	Good Combustion Practices	Stack Test	
IA-0083	IA	ROQUETTE AMERICA, INC.	CFB	996	Coal, Petcoke, Biomass, TDF	8/16/2006	0.009	3-hour	Good Combustion Practices	Stack Test	2
LA-0201	LA	WEYERHAEUSER - RED RIVER MILL	Unknown	940	Wood, Sludge, Recycle Fiber, Gas	5/24/2006	0.01	3-hour	Good Combustion Practices	None	
MA-02a	MA	RUSSELL BIOMASS	BFB	740	Clean Wood	12/30/2008	0.01	3-hour	Good Combustion Practices	None	
MA-02b	MA	RUSSELL BIOMASS	Stoker	740	Clean Wood	12/30/2008	0.01	3-hour	Oxidation catalyst	None	
MA-03	MA	PIONEER RENEWABLE ENERGY	Stoker	663	Wood	Application	0.01	3-hour	Oxidation catalyst	None	
CT-03	CT	WATERTOWN RENEWABLE POWER	FB Gasification	436	Biomass, Natural Gas (startup)	Draft 2009	0.01	3-hour	Good Combustion Practices	Stack Test	
CT-02	CT	PLAINFIELD RENEWABLE ENERGY	FB Gasification	523.1	Biomass, biodiesel	2008	0.012	3-hour	Good Combustion Practices	Stack Test	
IA-0095	IA	TATE & LYLE INGREDIENTS AMERICAS, INC.	Unknown	200	Corn Fibers, Gas, Biogas, Process Gas	9/19/2008	0.012	3-hour	Good Combustion Practices	Stack Test	
MI-0258	MI	TES FILER CITY STATION	Stoker	384	Coal, Wood, TDF	4/5/2001	0.01	3-hour	Good Combustion Practices	None	2
OH-0307	OH	SOUTH POINT BIOMASS GENERATION	Stoker	318	Wood	4/4/2006	0.013	3-hour	Oxidation Catalyst	Stack Test	
TX-31	TX	NACOGDOCHES POWER PLANT, AMERICAN RENEWABLES	BFB	1374	Biomass, Gas	3/1/2007	0.013	30-day	Good Combustion Practices	Stack Test	
LA-0125	LA	WEYERHAEUSER COMPANY, DODSON SAWMILL	Unknown	233	Wood/Bark	10/29/2007	0.017	3-hour	Good Combustion Practices	None	2
LA-0218	LA	FLORIEN PLYWOOD PLANT, BOISE BUILDING SOLUTIONS	Unknown	225	Wood, Natural Gas	7/18/2007	0.017	1-hour	Good Combustion Practices	None	
MI-0285	MI	GRA YLING GENERATING STATION	Stoker	523	Wood, TDF	9/18/2001	0.017	3-hour	Good Combustion Practices	Stack Test	2
WA-0327	WA	SKAGIT COUNTY LUMBER MILL	Stoker	430	Biomass	12/12/2005	0.019	1-hour	Good Combustion Practices	Stack Test	
GA-02	GA	YELLOW PINE ENERGY COMPANY	BFB	1529	Biomass, TDF, Propane, Fuel Oil	5/15/2009	0.02	3-hour	Good Combustion Practices	Stack Test	

1. Not a BACT limit.
2. Based on lb/hr limit and maximum permitted capacity.
3. LAER limit.

High-efficiency drift eliminators are the best method for minimizing drift loss from wet cooling towers. The mist elimination system proposed for this project will minimize drift losses to 0.0005%, which is equivalent to the lowest RBLC determinations presented in Table 5-16.

5.11. ELECTRIC HOGGER - VOC BACT

VOC emissions from the electric hogger that is used to chip oversized biomass delivered to the facility are considered fugitive emissions and add on emission controls are not practicable. Therefore, no control is proposed for VOC emissions from the electric hogger.

5.12. SUMMARY OF PROPOSED BACT PRIMARY LIMITS

Table 5-18 presents a summary of the proposed primary BACT determinations and limits for the Biomass Cogeneration Boiler and other emission units at the facility. Note the CFB boiler primary limits only apply during periods of normal operation; secondary limits, as discussed in the following section, will apply during periods that encompass startup and shutdown events.

TABLE 5-18. SUMMARY OF PROPOSED PRIMARY BACT DETERMINATIONS

Unit	Pollutant ¹	Limit	Units	Averaging Period	Proposed BACT
CFB Boiler	NO _x	0.075	lb/MMBtu	30-day	Selective Non-Catalytic Reduction
	SO ₂	0.020	lb/MMBtu	30-day	Duct Sorbent Injection
	PM/PM ₁₀ /PM _{2.5} (Filterable)	0.0098	lb/MMBtu	3-hour	Baghouse
	PM ₁₀ /PM _{2.5} (Total)	0.0260	lb/MMBtu	3-hour	Baghouse
	CO	0.10	lb/MMBtu	30-day	Good Design and Operating Practices
	VOC	0.0070	lb/MMBtu	3-hour	Good Design and Operating Practices
Hogger	VOC				No Control
Sorbent Storage Silo	PM/PM ₁₀ /PM _{2.5}	0.005	gr/cf	3-hour	Bin Vent Filter ²
Fly Ash Storage Silo	PM/PM ₁₀ /PM _{2.5}	0.005	gr/cf	3-hour	Bin Vent Filter ²
Cooling Tower	PM/PM ₁₀ /PM _{2.5}	0.0005%	drift	N/A	Drift Eliminators
Biomass Storage Pile	PM/PM ₁₀ /PM _{2.5}				Inherent Moisture Content
	VOC				No Control

1. Compliance with PM_{2.5} limits is assumed inherent with compliance with PM₁₀ limits as vendors did not provide PM_{2.5} estimates.

2. The bin vent filter is a type of fabric filter.

TABLE 5-15. MOST STRINGENT RBLC ENTRIES FOR SILO CONTROL

ID	State	Company/Facility ¹	Process	Throughput (tons/hr)	Permit Date	PM (gr/cf)	PM ₁₀ (gr/cf)	Control Type
*LA-0231	LA	LAKE CHARLES GASIFICATION FACILITY	SAND/BOTTOM ASH SILOS AND DAY BINS	N/A	6/22/2009	0.005	-	Baghouse
OH-0317	OH	OHIO RIVER CLEAN FUELS, LLC	FLYASH HANDLING SYSTEM	95.4	11/20/2008	0.005	-	Baghouse
OH-0321b	OH	MARTIN MARIETTA MATERIALS	LIME LOAD-OUT, TRANSFER, STORAGE	300	11/13/2008	0.005	0.005	Baghouse
*IA-0095	IA	TATE & LYLE INDGREDIENTS AMERICAS, INC.	ASH STORAGE BIN/LOADOUT	N/A	9/19/2008	0.005	0.005	Dust Collector
*IA-0095	IA	TATE & LYLE INDGREDIENTS AMERICAS, INC.	LIME SILO	150	9/19/2008	0.005	0.005	Dust Collector
ND-0024	ND	SPIRITWOOD STATION	MATERIALS HANDLING	60	9/14/2007	0.005	-	Baghouse
IA-0089	IA	HOMELAND ENERGY SOLUTIONS, LLC, PN 06-672	ASH STORAGE AND HANDLING	250	8/8/2007	0.005	0.005	Baghouse
*IA-0086	IA	UNIVERSITY OF NORTHERN IOWA	LIMESTONE SILO	10	5/3/2007	0.005	0.005	Baghouse
ND-0021	ND	GASCOYNE GENERATING STATION	MATERIAL HANDLING	N/A	6/3/2005	0.005	-	Baghouse
AL-0220a	AL	CHEMICAL LIME COMPANY - O'NEAL PLANT	LIME HANDLING & STORAGE	N/A	3/23/2005	0.005	-	Unknown
OH-0321c	OH	MARTIN MARIETTA MATERIALS	DUST LOAD-OUT SYSTEM	100	11/13/2008	0.01	0.01	Baghouse
WV-0024	WV	WESTERN GREENBRIER CO-GENERATION, LLC	ASH HANDLING	105	4/26/2006	0.01	-	Fabric Filters
WV-0024	WV	WESTERN GREENBRIER CO-GENERATION, LLC	LIMESTONE HANDLING	100	4/26/2006	0.01	0.01	Fabric Filters
CO-0057c	CO	COMANCHE STATION	RECYCLE ASH HANDLING	N/A	7/5/2005	0.01	-	Baghouse
CO-0057	CO	COMANCHE STATION	LIME HANDLING	N/A	7/5/2005	0.01	0.01	Baghouse

1. Only entires from 2005 and on with gr/cf limit of 0.01 or less are listed.

TABLE 5-16. MOST STRINGENT RBLC ENTRIES FOR COOLING TOWERS

ID	State	Company/Facility ¹	Unit	Throughput (gpm)	Permit Date	PM Limit (% drift)	PM ₁₀ Limit (% drift)	Control Type	Note(s)
MT-0030	MT	BILLINGS REFINERY	COOLING TOWER	10,000	11/19/2008	-	0.0005	Drift Eliminator	
MD-0040	MD	CPV ST CHARLES	COOLING TOWER	N/A	11/12/2008	0.0005	0.0005	Drift Eliminator	2
AR-0094	AR	JOHN W. TURK JR. POWER PLANT	COOLING TOWER	N/A	11/5/2008	-	0.0005	Drift Eliminator	3
*IA-0095	IA	TATE & LYLE INGREDIENTS AMERICAS, INC.	COOLING TOWER (4 CELLS)	30,000	9/19/2008	0.0005	0.0005	Drift Eliminator	
*FL-0304	FL	CANE ISLAND POWER PARK	COOLING TOWER (8 CELLS)	N/A	9/8/2008	0.0005	-	Drift Eliminator	
*FL-0303	FL	FPL WEST COUNTY ENERGY CENTER UNIT 3	COOLING TOWER (26 CELLS)	304,000	7/30/2008	0.0005	-	Drift Eliminator	
FL-0299	FL	CRYSTAL RIVER POWER PLANT	COOLING TOWER	342,306	10/12/2007	0.0005	-	Drift Eliminator	
ND-0024	ND	SPIRITWOOD STATION	COOLING TOWER	80,000	9/14/2007	0.0005	-	Drift Eliminator	
IA-0089	IA	HOMELAND ENERGY SOLUTIONS, LLC, PN 06-672	COOLING TOWER	50,000	8/8/2007	0.0005	0.0005	Drift Eliminator	
IA-0088	IA	ADM CORN PROCESSING - CEDAR RAPIDS	COOLING TOWER	150,000	6/29/2007	0.0005	0.0005	Drift Eliminator	
*FL-0286	FL	FPL WEST COUNTY ENERGY CENTER	COOLING TOWER (26 CELLS)	306,000	1/10/2007	0.0005	-	Drift Eliminator	
FL-0294	FL	ANCLOTE POWER PLANT	COOLING TOWER	660,000	12/22/2006	0.0005	-	Drift Eliminator	
CO-0057	CO	COMANCHE STATION	COOLING TOWER	140,650	7/5/2005	0.0005	0.0005	Drift Eliminator	
NV-0036	NV	TS POWER PLANT	COOLING TOWER	N/A	5/5/2005	-	0.0005	Drift Eliminator	
NY-0093	NY	TRIGEN-NASSAU ENERGY CORPORATION	COOLING TOWER	N/A	3/31/2005	-	0.0005	Drift Eliminator	
WA-0329	WA	DARRINGTON ENERGY COGENERATION POWER	COOLING TOWER	N/A	2/11/2005	0.001	-	Drift Eliminator	
*WA-0328	WA	BP CHERRY POINT COGENERATION PROJECT	COOLING TOWER	N/A	1/11/2005	0.001	-	Drift Eliminator	

1. Only RBLC entries with % drift limits of 0.001% and smaller are listed.
2. LAER limit for PM_{2.5}, not a BACT limit.
3. Also includes a lb/hr emission limit.

5.13. BIOMASS COGENERATION BOILER SECONDARY BACT EMISSION LIMITS

The primary BACT emission limits discussed in earlier sections are rate-based limits based on the boiler heat input (lb/MMBtu), which means that for every unit of heat consumed by the boiler, there will be no more than “X” amount of emissions. These limits reflect what are expected to be the achievable emission rates using the respective control technology during periods of normal boiler operation. However, emission limits that directly correspond to the instantaneous heat input of the boiler may not be appropriate during periods of startup and shutdown. It should be noted that P&GPP is planning only one scheduled outage (one startup/shutdown) per year for typical maintenance activities. During these conditions, the amount of fuel, and thus heat input, is lower than during typical operation, which therefore linearly decreases the emission limits.

Emissions during startup will be minimized using clean fuel and good operating practices. During the first approximately 6 hours of startup, the boiler will be operating at up to 200 MMBtu/hr using natural gas to heat the boiler refractory to prevent damage to the boiler system. During this time, the baghouse is bypass to prevent condensation in the baghouse. After approximately 6 hours, biomass begins to be introduced into the system and the baghouse and sorbent injection systems are engaged. At approximately Hour 7, the heat input for biomass reaches approximately 475 MMBtu/hr and natural gas heat input is at 200 MMBtu/yr. At this point the temperature profile of heat gases exiting the boiler is within the appropriate range to engage the SNCR control system. Natural gas is throttled back such that by approximately Hour 8, no additional natural gas is needed as the biomass heat input is continuously ramped up until full load condition is achieved.

APPENDIX A: CONSTRUCTION PERMIT APPLICATION FORMS

Title V Certification Form
SIP Forms

Certifications and Signatures

Facility Name: The Procter & Gamble Paper Products Company, Albany, Georgi

Project Name: 2013 Cogeneration Biomass Boiler Installation

AIRS Number: 130950071

Submittal File Name: 130950071_20130611.mdb

COMPUTER DISK VIRUS EXAMINATION CERTIFICATION:

I certify that, to the best of my knowledge, the completed electronic application disk has been inspected and found free of any known viruses.

Signature: _____

Date: _____

Name (print): _____

Official Title: _____

SOFTWARE USAGE CERTIFICATION:

I certify that the software used to complete the Georgia Title V application was used as provided by the Georgia Environmental Protection Division, Air Protection Branch and was unaltered in any way. I understand that the submission of a Title V (Part 70) application completed using any altered version of the provided software constitutes the submission of an incomplete application and that such action may be subject to enforcement by the Georgia Air Protection Branch and/or the US EPA.

CERTIFICATION OF COMPLIANCE:

Except as stated on the Compliance Plan For a Non-Compliant Emission Unit or Group form of this application, I hereby certify that this facility is in compliance with all applicable requirements effective as of the date of this certification and will continue to comply with such requirements. For applicable requirements promulgated as of the date of this certification, that will become effective during the permit term, I further certify that, except as stated on the Compliance Plan For a Non-Compliant Emission Unit or Group form of this application, this facility will comply with such requirements and will continue to comply with such requirements.

I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this application and all of its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are, to the best of my knowledge and belief, true, accurate and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Unless otherwise required by the Director, compliance certifications will be submitted to the Director at least annually.

SIGNATURE OF RESPONSIBLE OFFICIAL:

Signature: _____ Date: _____

Name (print): Fidel Torres

Official Title: Plant Manager

Address: 512 Liberty Expressway Southeast
Albany, GA 31702

Notary Public Certification of Responsible Official's Signature:

Signature of Notary Public: _____



SIP AIR PERMIT APPLICATION

EPD Use Only

Date Received: _____ Application No. _____

FORM 1.00: GENERAL INFORMATION

1. Facility Information

Facility Name: The Procter & Gamble Paper Products Company
AIRS No. (if known): 04-13- 095 - 0071
Facility Location: Street: 512 Liberty Expressway Southeast
City: Albany Georgia Zip: 31705 County: Dougherty
Is this facility a "small business" as defined in the instructions? Yes: ☐ No: ☒

2. Facility Coordinates

Latitude: 31° 32' 57" **NORTH** Longitude: 84° 06' 41" **WEST**
UTM Coordinates: 774213 **EAST** 3493872 meters **NORTH** **ZONE** 16
meters

3. Facility Owner

Name of Owner: The Procter & Gamble Company
Owner Address Street: 1 P&G Plaza
City: Cincinnati State: Ohio Zip: 45202

4. Permitting Contact and Mailing Address

Contact Person: Tracey Paul Title: Site Environmental Leader
Telephone No.: (229) 430-8260 Ext. 3109 Fax No.: (513) 277-6748
Email Address: paul.tk@pg.com
Mailing Address: Same as: ☐ Facility Location: ☐ Owner Address: ☐ Other: ☒
If Other: Street Address: P.O. Box 1747
City: Albany State: Georgia Zip: 31702

5. Authorized Official

Name: Fidel Torres Title: Plant Manager
Address of Official Street: 512 Liberty Expressway Southeast
City: Albany State: Georgia Zip: 31702

This application is submitted in accordance with the provisions of the Georgia Rules for Air Quality Control and, to the best of my knowledge, is complete and correct.

Signature: _____ Date: _____

6. Reason for Application: (Check all that apply)

- ☐ New Facility (to be constructed)
 ☐ Revision of Data Submitted in an Earlier Application
- ☒ Existing Facility (initial or modification application)
 Application No.: _____
- ☒ Permit to Construct
 Date of Original Submittal: _____
- ☒ Permit to Operate
- ☐ Change of Location
- ☐ Permit to Modify Existing Equipment: Affected Permit No.: _____

7. Permitting Exemption Activities (for permitted facilities only):

Have any exempt modifications based on emission level per Georgia Rule 391-3-1-.03(6)(i)(3) been performed at the facility that have not been previously incorporated in a permit?

- ☒ No
 ☐ Yes, please fill out the SIP Exemption Attachment (See Instructions for the attachment download)

8. Has assistance been provided to you for any part of this application?

- ☐ No
 ☐ Yes, SBAP
 ☒ Yes, a consultant has been employed or will be employed.

If yes, please provide the following information:

Name of Consulting Company: Trinity Consultants

Name of Contact: Joe Sullivan

Telephone No.: 919-462-9693 Fax No.: 919-462-9694

Email Address: jsullivan@trinityconsultants.com

Mailing Address: Street: One Copley Parkway, Suite 310

City: Morrisville State: NC Zip: 27560

Describe the Consultant's Involvement:

Trinity Consultants is handling the preparation of the permit application with information supplied to them by The Procter & Gamble Paper Products Company

9. Submitted Application Forms: Select only the necessary forms for the facility application that will be submitted.

No. of Forms	Form
1	2.00 Emission Unit List
1	2.01 Boilers and Fuel Burning Equipment
	2.02 Storage Tank Physical Data
	2.03 Printing Operations
	2.04 Surface Coating Operations
	2.05 Waste Incinerators (solid/liquid waste destruction)
	2.06 Manufacturing and Operational Data
1	3.00 Air Pollution Control Devices (APCD)
1	3.01 Scrubbers
1	3.02 Baghouses & Other Filter Collectors
	3.03 Electrostatic Precipitators
1	4.00 Emissions Data
1	5.00 Monitoring Information
11	6.00 Fugitive Emission Sources
	7.00 Air Modeling Information

10. Construction or Modification Date

Estimated Start Date: 4th Quarter 2013

11. If confidential information is being submitted in this application, were the guidelines followed in the "Procedures for Requesting that Submitted Information be treated as Confidential"?

☒ No ☐ Yes

12. New Facility Emissions Summary

Criteria Pollutant	New Facility	
	Potential (tpy)	Actual (tpy)
Carbon monoxide (CO)	N/A	N/A
Nitrogen oxides (NOx)		
Particulate Matter (PM) (filterable only)		
PM <10 microns (PM10)		
PM <2.5 microns (PM2.5)		
Sulfur dioxide (SO ₂)		
Volatile Organic Compounds (VOC)		
Greenhouse Gases (GHGs) (in CO ₂ e)		
Total Hazardous Air Pollutants (HAPs)		
Individual HAPs Listed Below:		

13. Existing Facility Emissions Summary

Criteria Pollutant	Current Facility		After Modification	
	Potential (tpy)	Actual (tpy)	Potential (tpy)	Actual (tpy)
Carbon monoxide (CO)	See Attached	Table		
Nitrogen oxides (NOx)				
Particulate Matter (PM) (filterable only)				
PM <10 microns (PM10)				
PM <2.5 microns (PM2.5)				
Sulfur dioxide (SO ₂)				
Volatile Organic Compounds (VOC)				
Greenhouse Gases (GHGs) (in CO ₂ e)				
Total Hazardous Air Pollutants (HAPs)				
Individual HAPs Listed Below:				
See Attached Table				

FORM 1.00 EXISTING FACILITY EMISSION SUMMARY

Note: These sources are not yet operating and are designed for continuous operation at maximum capacity. Therefore, actual emission rates are equal to potential emission rates.

	Actual Emission Rates Prior to Modification	Potential Emission Rates Prior to Modification	Potential Emission for Modification	Potential Emission Rates After Modification
Pollutant Emitted	tpv	tpv	tpv	tpv
Total Particulate Matter (PM)	250.00	450.00	118.79	568.79
Total Particulate Matter<10 microns (PM ₁₀)	250.00	450.00	118.55	568.55
Total Particulate Matter<2.5 microns (PM _{2.5})	250.00	450.00	8.33	458.33
Sulfur Dioxide (SO ₂)	680.00	800.00	90.93	890.93
Nitrogen Oxides (NO _x)	1500.0	2000.0	340.7	2340.7
Carbon Monoxide (CO)	1500.0	2000.0	454.2	2454.2
Volatile Organic Compounds (VOC)	400.00	1000.00	82.76	1082.76
Lead	<10	<10	0.22	<10
CO ₂ e	>25,000	>25,000	20,588	70,588
Acetaldehyde	<10	<10	3.77E+00	<10
Acetophenone	<10	<10	1.45E-05	<10
Acenaphthene	<10	<10	1.55E-06	<10
Acenaphthylene	<10	<10	1.55E-06	<10
Acrolein	<10	<10	1.82E+01	10-25
Ammonia	<10	<10	9.48E+01	>25
Antimony & Compounds	<10	<10	3.59E-02	<10
Arsenic & Compounds	<10	<10	9.99E-02	<10
Benzene	<10	<10	1.91E+01	10-25
Benzo(b,k)fluoranthene	<10	<10	1.52E-09	<10
Benzo(g,h,i)perylene	<10	<10	1.01E-09	<10
Benzo(a)pyrene	<10	<10	1.18E-02	<10
Beryllium metal	<10	<10	5.00E-03	<10
Cadmium Metal	<10	<10	1.86E-02	<10
Carbon tetrachloride	<10	<10	2.04E-01	<10
Chlorine	<10	<10	3.59E+00	<10
Chlorobenzene	<10	<10	1.50E-01	<10
Chloroform	<10	<10	1.27E-01	<10
Chromium-Other compds	<10	<10	7.95E-02	<10
Chrysene	<10	<10	1.52E-09	<10
Cobalt compounds	<10	<10	2.95E-02	<10
Dibenzo(a,h)anthracene	<10	<10	1.01E-09	<10
Dinitrophenol, 2,4-	<10	<10	8.18E-04	<10
Di(2-ethylhexyl)phthalate (DEHP)	<10	<10	2.13E-04	<10
Ethyl benzene	<10	<10	1.41E-01	<10
Ethylene dichloride (1,2-dichloroethane)	<10	<10	1.32E-01	<10
Fluoranthene	<10	<10	2.53E-09	<10
Fluorene	<10	<10	2.36E-09	<10
Formaldehyde	<10	<10	2.00E+01	10-25
Hexachlorodibenzo-p-dioxin 1,2,3,6,7,8	<10	<10	7.27E-03	<10
Hydrogen chloride (hydrochloric acid)	<10	<10	9.08E+01	>25
Hydrogen fluoride	<10	<10	4.04E+02	>25
Indo(1,2,3-cd)pyrene	<10	<10	1.52E-09	<10
Lead and Lead compounds	<10	<10	2.18E-01	<10
Manganese & compounds	<10	<10	7.27E+00	10-25
Mercury, vapor (Include in Mercury & Compds)	<10	<10	3.63E-03	<10
Methanol	10-25	10-25	0.00E+00	10-25
Methyl bromide (bromomethane)	<10	<10	6.81E-02	<10
Methyl chloride (chloromethane)	<10	<10	1.04E-01	<10
Methyl chloroform (1,1,1 trichloroethane)	<10	<10	1.41E-01	<10
Methyl ethyl ketone	<10	<10	2.45E-02	<10
Methylene chloride (dichloromethane)	<10	<10	1.32E+00	<10
Naphthalene	<10	<10	4.41E-01	<10
Nickel metal (Component of Nickel & Compounds)	<10	<10	1.50E-01	<10
Nitrophenol, 4-	<10	<10	5.00E-04	<10
Pentachlorophenol	<10	<10	2.32E-04	<10
Perchloroethylene (tetrachloroethylene)	<10	<10	1.73E-01	<10
Phenanthrene	<10	<10	1.43E-08	<10
Phenol	<10	<10	2.32E-01	<10
Phosphorus Metal, Yellow or White	<10	<10	1.23E-01	<10
Polychlorinated biphenyls	<10	<10	3.70E-05	<10
Polycyclic Organic Matter	<10	<10	5.68E-01	<10
Propionaldehyde	<10	<10	2.77E-01	<10
Propylene dichloride (1,2 dichloropropane)	<10	<10	1.50E-01	<10
Pyrene	<10	<10	4.21E-09	<10
Selenium compounds	<10	<10	1.27E-02	<10
Silver	<10	<10	7.72E+00	<10
Styrene	<10	<10	8.63E+00	10-25
Tetrachlorodibenzo-p-dioxin, 2,3,7,8-	<10	<10	3.91E-08	<10
Toluene	<10	<10	4.18E+00	<10
Trichloroethylene	<10	<10	1.36E-01	<10
Trichlorofluoromethane (CFC 111)	<10	<10	1.86E-01	<10
Trichlorophenol, 2,4,6-	<10	<10	9.99E-05	<10
Vinyl chloride	<10	<10	8.18E-02	<10
Xylene, o-	<10	<10	1.14E-01	<10
Total HAPs	<10	<10	585.0	>25

14. 4-Digit Facility Identification Code:

SIC Code: 2676 SIC Description: Sanitary Paper Products
 NAICS Code: 322291 NAICS Description: Sanitary Paper Products Manufacturing

15. Description of general production process and operation for which a permit is being requested. If necessary, attach additional sheets to give an adequate description. Include layout drawings, as necessary, to describe each process. References should be made to source codes used in the application.

The Procter & Gamble Paper Products Company (P&G) is planning to construct a new 1,037 MMBtu/hr Cogeneration Biomass Boiler that will provide approximately 50 percent of its steam to P&G and the balance of steam to produce electricity for the grid. Following complete of the shake-down period, Biomass Boiler No. 2 (Emission Unit B002) will be decommissioned.

16. Additional information provided in attachments as listed below:

Attachment A - See Table of Contents with accompanying report
 Attachment B - _____
 Attachment C - _____
 Attachment D - _____
 Attachment E - _____
 Attachment F - _____

17. Additional Information: Unless previously submitted, include the following two items:

- ☒ Plot plan/map of facility location or date of previous submittal: Site location and facility layout provided in Volume II of the report.
☒ Flow Diagram or date of previous submittal: Flow diagram provided in Section 2.

18. Other Environmental Permitting Needs:

Will this facility/modification trigger the need for environmental permits/approvals (other than air) such as Hazardous Waste Generation, Solid Waste Handling, Water withdrawal, water discharge, SWPPP, mining, landfill, etc.?

☐ No ☒ Yes, please list below:

Construction Stormwater Control Plan (SWPPP), Sediment Erosion, Stormwater

Facility Name: The Procter & Gamble Paper
Products Company

Date of Application:

June 2013

FORM 2.00 – EMISSION UNIT LIST

Emission Unit ID	Name	Manufacturer and Model Number	Description
B004	Biomass Cogeneration Boiler	Fluid Bed Boiler/ TBD	1,037 MMBtu/hr Wood-fired Cogeneration Boiler
CT-1	Cooling Tower	TBD	Cools recirculating water from the boiler.
SP-01	Storage Pile	N/A	Biomass Storage Pile
SS1	Sorbent Silo	TBD	Sorbent silo for the storage of sorbent for trona or sodium bicarbonate injection
FAS1	Flyash Silo	TBD	A flyash silo equipped with fabric filtration system
HOG1	Biomass Hogger	TBD	Enclosed electric hogger for size reduction of oversized wood brought in for the Cogen Boiler.

Facility Name: The Procter & Gamble Paper Products Company **Date of Application:** June 2013

FORM 2.01 – BOILERS AND FUEL BURNING EQUIPMENT

[illegible]

¹ This column does not have to be completed for natural gas only fired equipment.

Facility Name: The Procter & Gamble Paper Products Company

Date of Application: June 2013

FUEL DATA

Emission Unit ID	Fuel Type	Potential Annual Consumption				Hourly Consumption		Heat Content		Percent Sulfur		Percent Ash in Solid Fuel	
		Total Quantity		Percent Use by Season		Max.	Avg.	Min.	Avg.	Max.	Avg.	Max.	Avg.
		Amount	Units	Ozone Season May 1 - Sept 30	Non-ozone Season Oct 1 - Apr 30								
B004	Biomass	983,130	ton/yr	40	60	112 tons/hr		4,200 Btu/lb		0.02		1.10	
B004	Natural Gas	4,705,882	scf/yr	40	60	196,078 scf/hr		1,020 BTU/scf		0.0015		n/a	

Fuel Supplier Information

Fuel Type	Name of Supplier	Phone Number	Supplier Location			
			Address	City	State	Zip
Biomass	American Southern Forest Products	(229) 782-7185	6789 N Highway 133	Doerun	GA	31744
Biomass	BIO Plus	(229) 567-3566	1515 Industrial Drive	Ashburn	GA	31714
Biomass	Gilman Building Products Co.	(229) 423-8761	173 Peachtree Road	Fitzgerald	GA	31750
Biomass	McClesky Mills	(229) 846-2003	197 Rhodes Street	Smithville	GA	31787
Biomass	John B. Sanfilippo & Son	(229) 246-6887	1251 Colquitt Highway	Bainbridge	GA	39817
Natural Gas	Texican Industrial Energy Marketing	(404) 231-1165	2839 Paces Ferry Road, Suite 1150	Atlanta	GA	30339

Facility Name:**Date of Application:**

Form 3.00 – AIR POLLUTION CONTROL DEVICES - PART A: GENERAL EQUIPMENT INFORMATION

[illegible]

Facility Name: The Procter & Gamble Paper Products CompanyDate of Application: June 2013**Form 3.00 – AIR POLLUTION CONTROL DEVICES – PART B: EMISSION INFORMATION**

APCD Unit ID	Pollutants Controlled	Percent Control Efficiency		Inlet Stream To APCD		Exit Stream From APCD		Pressure Drop Across Unit (Inches of water)
		Design	Actual	lb/hr	Method of Determination	lb/hr	Method of Determination	
SNCR-1	NOx	62	TBD	207	Engineering Determination; ESI Inc. of Tennessee	77.8	Engineering Determination; ESI Inc. of Tennessee	N/A
SI-1	HCl	88.77	TBD	184.6	Engineering Determination; ESI Inc. of Tennessee	20.7	Engineering Determination; ESI Inc. of Tennessee	N/A
SI-1	SO2	92	TBD	269.4	Engineering Determination; ESI Inc. of Tennessee	20.7	Engineering Determination; ESI Inc. of Tennessee	N/A
BH-1	PM/PM10/PM2.5	99/98/95	TBD	1327.4/ 547.5/ 190.8	Engineering Determination; ESI Inc. of Tennessee	27.8	Engineering Determination; ESI Inc. of Tennessee	6
FAS1 VF-1	TSP/PM10/PM2.5	0.01 gr/ft3	0.01 gr/ft3	8.57	Engineering Determination; ESI Inc. of Tennessee	0.0857	Engineering Determination; ESI Inc. of Tennessee	N/A
SS1 VF-2	TSP/PM10/PM2.5	0.01 gr/ft3	0.01 gr/ft3	1.71	Engineering Determination; ESI Inc. of Tennessee	0.0171	Engineering Determination; ESI Inc. of Tennessee	N/A
ACI-1	Hg	72	TBD	0.01145	Engineering Determination; ESI Inc. of Tennessee	0.003	Engineering Determination; ESI Inc. of Tennessee	N/A

Facility Name: The Procter & Gamble Paper Products
Company

Date of Application:

June 2013

FORM 3.01 – SCRUBBERS

APCD Unit ID	Scrubber Type	Materials of Construction (Plastic, 1040 steel, etc.)	Scrubbant	pH Range	Pressure Drop Range (inches of H2O)	Minimum Scrubbant Flow Rate (Gal/min)	Is Scrubbant Recirculated?	Minimum Makeup Rate (Gal/min)	Size of Pond or Holding Tank (Acre-ft or gal)
SI-1	Dry Sorbent Injection	N/A	Sodium Bicarbonate/ Trona	N/A	N/A	N/A	<input type="checkbox"/>	11 lb/min	N/A
							<input type="checkbox"/>		
							<input type="checkbox"/>		
							<input type="checkbox"/>		
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June 2013

Facility Name: The Procter & Gamble Paper Products Company

Date of Application: June 2013

FORM 4.00 – EMISSION INFORMATION

Emission Unit ID	Air Pollution Control Device ID	Stack ID	Pollutant Emitted	Emission Rates				
				Hourly Actual Emissions (lb/hr)	Hourly Potential Emissions (lb/hr)	Actual Annual Emission (tpy)	Potential Annual Emission (tpy)	Method of Determination
B004	Note 1	Note 1	Note 1	Note 2	Note 1	Note 2	Note 1	Note 1
SS1	VF-2	EP-SS-1	PM/ PM10/ PM2.5	Note 2	0.017	Note 2	0.00257	Grain loading outlet concentration of 0.005 gr/ft3
FAS1	VF-1	EP-FS-1	PM/ PM10/ PM2.5	Note 2	0.0857	Note 2	0.0375	Grain loading outlet concentration of 0.005 gr/ft3
HOG-1	N/A	EP-HOG-1	VOC	Note 2	9,764	Note 2	48.82	NCASI Emission Factor
CT-1	N/A	EP-CT-1	PM/ PM10/ PM2.5	Note 2	0.10/ 0.06/ 0.0002	Note 2	0.44/ 0.25/ 0.0009	Calculated based on total dissolved solids and drift loss
SP-1	N/A	N/A	PM/ PM10/ PM2.5	Note 2	0.064/ 0.032/ 0.0048	Note 2	0.282/ 0.141/ 0.021	U.S. EPA Control of Open Fugitive Dust Sources. Research Triangle Park, North Carolina, EPA-450/3-88-008. September 1988, Page 4-17.
SP-1	N/A	N/A	VOC	Note 2	0.49	Note 2	2.15	NCASI Emission Factor
Note 1: Attached table contains boiler potential emissions.		Note 2: These sources are not yet operating. Therefore, actual = potential.						

**FORM 4.00 EMISSION INFORMATION
COGENERATION BIOMASS BOILER**

Note: These sources are not yet operating and are designed for continuous operation at maximum capacity. Therefore, actual emission rates are equal to potential emission rates.

Emission Unit	Air Pollution Control Device ID	Stack ID	Pollutant Emitted	Potential Emission Rates			Method of Determination
				lb/hr	lb/yr	tpy	
B0004	BH-1	EP-B0004	Filterable Particulate Matter (PM)	1.02E+01	89,024.38	44.51	lb/ MMBtu Emission Factor provided from ESI Inc of Tennessee.
B0004	BH-1	EP-B0004	Filterable Particulate Matter<10 microns (PM ₁₀)	1.02E+01	89,024.38	44.51	lb/ MMBtu Emission Factor provided from ESI Inc of Tennessee.
B0004	BH-1	EP-B0004	Filterable Particulate Matter<2.5 microns (PM _{2.5})	1.02E+01	89,024.38	44.51	lb/ MMBtu Emission Factor provided from ESI Inc of Tennessee.
B0004	BH-1	EP-B0004	Condensable Particulate Matter (PM _{cond})	1.76E+01	154,430.04	77.22	Uncontrolled emission factors (criteria and HAP/TAP) for wood combustion from AP-42; Compilation of Air Pollutant Emission Factors Vol. 1 - Stationary Sources USEPA, 5th ed. Section 1.6, 9/03
B0004	BH-1	EP-B0004	Total Particulate Matter (PM)	2.78E+01	243,454	121.73	lb/ MMBtu Emission Factor provided from ESI Inc of Tennessee + Condensable portion from AP-42
B0004	BH-1	EP-B0004	Total Particulate Matter<10 microns (PM ₁₀)	2.78E+01	243,454	121.73	lb/ MMBtu Emission Factor provided from ESI Inc of Tennessee + Condensable portion from AP-42
B0004	BH-1	EP-B0004	Total Particulate Matter<2.5 microns (PM _{2.5})	2.78E+01	243,454	121.73	lb/ MMBtu Emission Factor provided from ESI Inc of Tennessee + Condensable portion from AP-42
B0004	DSL-1	EP-B0004	Sulfur Dioxide (SO ₂)	2.08E+01	181,864	90.93	lb/ MMBtu Emission Factor provided from ESI Inc of Tennessee.
B0004	SNCR-1	EP-B0004	Nitrogen Oxides (NO _x)	7.78E+01	681,309	340.7	lb/ MMBtu Emission Factor provided from ESI Inc of Tennessee.
B0004	N/A	EP-B0004	Carbon Monoxide (CO)	1.04E+02	908,412	454.2	lb/ MMBtu Emission Factor provided from ESI Inc of Tennessee.
B0004	N/A	EP-B0004	Volatile Organic Compounds (VOC)	7.26E+00	63,589	31.79	Uncontrolled emission factors (criteria and HAP/TAP) for wood combustion from AP-42; Compilation of Air Pollutant Emission Factors Vol. 1 - Stationary Sources USEPA, 5th ed. Section 1.6, 9/03
B0004	N/A	EP-B0004	Lead	4.98E-02	436	0.22	Uncontrolled emission factors (criteria and HAP/TAP) for wood combustion from AP-42; Compilation of Air Pollutant Emission Factors Vol. 1 - Stationary Sources USEPA, 5th ed. Section 1.6, 9/03
B0004	N/A	EP-B0004	Carbon Dioxide (CO ₂)	2.02E+05	1,771,964,468	885.982	Uncontrolled emission factors (criteria and HAP/TAP) for wood combustion from AP-42; Compilation of Air Pollutant Emission Factors Vol. 1 - Stationary Sources USEPA, 5th ed. Section 1.6, 9/03
B0004	N/A	EP-B0004	Methane (CH ₄)	2.18E+01	190,777	95.39	Uncontrolled emission factors (criteria and HAP/TAP) for wood combustion from AP-42; Compilation of Air Pollutant Emission Factors Vol. 1 - Stationary Sources USEPA, 5th ed. Section 1.6, 9/03
B0004	N/A	EP-B0004	Nitrous Oxide (N ₂ O)	1.35E+01	118,095	59.05	Uncontrolled emission factors (criteria and HAP/TAP) for wood combustion from AP-42; Compilation of Air Pollutant Emission Factors Vol. 1 - Stationary Sources USEPA, 5th ed. Section 1.6, 9/03
B0004	N/A	EP-B0004	CO ₂ e	2.07E+05	1,812,580,118	906,290	CO ₂ e does not have an emission factor. CO ₂ e is the sum of Carbon Dioxide, Methane, and Nitrous Oxide.
B0004	N/A	EP-B0004	CO ₂ e biomass deferral	2.34E+04	41,176,718	20,588	CO ₂ e does not have an emission factor. CO ₂ e is the sum of Carbon Dioxide, Methane, and Nitrous Oxide.
B0004	N/A	EP-B0004	Acetaldehyde	8.61E-01	7,539.82	3.77E+00	Uncontrolled emission factors (criteria and HAP/TAP) for wood combustion from AP-42; Compilation of Air Pollutant Emission Factors Vol. 1 - Stationary Sources USEPA, 5th ed. Section 1.6, 9/03
B0004	N/A	EP-B0004	Acetophenone	3.32E-06	0.03	1.45E-05	Uncontrolled emission factors (criteria and HAP/TAP) for wood combustion from AP-42; Compilation of Air Pollutant Emission Factors Vol. 1 - Stationary Sources USEPA, 5th ed. Section 1.6, 9/03
B0004	N/A	EP-B0004	Acenaphthene	3.53E-07	0.00	1.55E-06	Uncontrolled and controlled emission factors (criteria and HAP/TAP) for natural gas combustion from Per AP-42, Section 1.4, 9/98.
B0004	N/A	EP-B0004	Acenaphthylene	3.53E-07	0.00	1.55E-06	Uncontrolled and controlled emission factors (criteria and HAP/TAP) for natural gas combustion from Per AP-42, Section 1.4, 9/98.
B0004	N/A	EP-B0004	Acrolein	4.15E+00	36,336.48	1.82E+01	Uncontrolled emission factors (criteria and HAP/TAP) for wood combustion from AP-42; Compilation of Air Pollutant Emission Factors Vol. 1 - Stationary Sources USEPA, 5th ed. Section 1.6, 9/03
B0004	N/A	EP-B0004	Ammonia	2.16E+01	189,500.80	9.48E+01	Ammonia emissions are calculated from the ammonia slip calculation in a separate spreadsheet provided later in this appendix.
B0004	N/A	EP-B0004	Antimony & Compounds	8.19E-03	71.76	3.59E-02	Uncontrolled emission factors (criteria and HAP/TAP) for wood combustion from AP-42; Compilation of Air Pollutant Emission Factors Vol. 1 - Stationary Sources USEPA, 5th ed. Section 1.6, 9/03
B0004	N/A	EP-B0004	Arsenic & Compounds	2.28E-02	199.85	9.99E-02	Uncontrolled emission factors (criteria and HAP/TAP) for wood combustion from AP-42; Compilation of Air Pollutant Emission Factors Vol. 1 - Stationary Sources USEPA, 5th ed. Section 1.6, 9/03
B0004	N/A	EP-B0004	Benzene	4.36E+00	38,153.30	1.91E+01	Uncontrolled emission factors (criteria and HAP/TAP) for wood combustion from AP-42; Compilation of Air Pollutant Emission Factors Vol. 1 - Stationary Sources USEPA, 5th ed. Section 1.6, 9/03
B0004	N/A	EP-B0004	Benzo(b,k)fluoranthene	3.46E-10	0.00	1.52E-09	Uncontrolled and controlled emission factors (criteria and HAP/TAP) for natural gas combustion from Per AP-42, Section 1.4, 9/98.
B0004	N/A	EP-B0004	Benzo(g,h,i)perylene	2.31E-10	0.00	1.01E-09	Uncontrolled and controlled emission factors (criteria and HAP/TAP) for natural gas combustion from Per AP-42, Section 1.4, 9/98.
B0004	N/A	EP-B0004	Benzo(a)pyrene	2.70E-03	23.62	1.18E-02	Uncontrolled emission factors (criteria and HAP/TAP) for wood combustion from AP-42; Compilation of Air Pollutant Emission Factors Vol. 1 - Stationary Sources USEPA, 5th ed. Section 1.6, 9/03
B0004	N/A	EP-B0004	Beryllium metal	1.14E-03	9.99	5.00E-03	Uncontrolled emission factors (criteria and HAP/TAP) for wood combustion from AP-42; Compilation of Air Pollutant Emission Factors Vol. 1 - Stationary Sources USEPA, 5th ed. Section 1.6, 9/03
B0004	N/A	EP-B0004	Cadmium Metal	4.25E-03	37.24	1.86E-02	Uncontrolled emission factors (criteria and HAP/TAP) for wood combustion from AP-42; Compilation of Air Pollutant Emission Factors Vol. 1 - Stationary Sources USEPA, 5th ed. Section 1.6, 9/03
B0004	N/A	EP-B0004	Carbon tetrachloride	4.67E-02	408.79	2.04E-01	Uncontrolled emission factors (criteria and HAP/TAP) for wood combustion from AP-42; Compilation of Air Pollutant Emission Factors Vol. 1 - Stationary Sources USEPA, 5th ed. Section 1.6, 9/03
B0004	N/A	EP-B0004	Chlorine	8.19E-01	7,176.45	3.59E+00	Uncontrolled emission factors (criteria and HAP/TAP) for wood combustion from AP-42; Compilation of Air Pollutant Emission Factors Vol. 1 - Stationary Sources USEPA, 5th ed. Section 1.6, 9/03
B0004	N/A	EP-B0004	Chlorobenzene	3.42E-02	299.78	1.50E-01	Uncontrolled emission factors (criteria and HAP/TAP) for wood combustion from AP-42; Compilation of Air Pollutant Emission Factors Vol. 1 - Stationary Sources USEPA, 5th ed. Section 1.6, 9/03

Emission Unit	Air Pollution Control Device ID	Stack ID	Pollutant Emitted	Potential Emission Rates			Method of Determination
				lb/hr	lb/yr	tpy	
B0004	N/A	EP-B0004	Chloroform	2.90E-02	254.36	1.27E-01	Uncontrolled emission factors (criteria and HAP/TAP) for wood combustion from AP-42; Compilation of Air Pollutant Emission Factors Vol. 1 - Stationary Sources USEPA, 5th ed. Section 1.6, 9/03
B0004	N/A	EP-B0004	Chromium-Other compds	1.81E-02	158.97	7.95E-02	Uncontrolled emission factors (criteria and HAP/TAP) for wood combustion from AP-42; Compilation of Air Pollutant Emission Factors Vol. 1 - Stationary Sources USEPA, 5th ed. Section 1.6, 9/03
B0004	N/A	EP-B0004	Chrysene	3.46E-10	0.00	1.52E-09	Uncontrolled and controlled emission factors (criteria and HAP/TAP) for natural gas combustion from Per AP-42, Section 1.4, 9/98.
B0004	N/A	EP-B0004	Cobalt compounds	6.74E-03	59.05	2.95E-02	Uncontrolled emission factors (criteria and HAP/TAP) for wood combustion from AP-42; Compilation of Air Pollutant Emission Factors Vol. 1 - Stationary Sources USEPA, 5th ed. Section 1.6, 9/03
B0004	N/A	EP-B0004	Dibenzo(a,h)anthracene	2.31E-10	0.00	1.01E-09	Uncontrolled and controlled emission factors (criteria and HAP/TAP) for natural gas combustion from Per AP-42, Section 1.4, 9/98.
B0004	N/A	EP-B0004	Dinitrophenol, 2,4-	1.87E-04	1.64	8.18E-04	Uncontrolled emission factors (criteria and HAP/TAP) for wood combustion from AP-42; Compilation of Air Pollutant Emission Factors Vol. 1 - Stationary Sources USEPA, 5th ed. Section 1.6, 9/03
B0004	N/A	EP-B0004	Di(2-ethylhexyl)phthalate (DEHP)	4.87E-05	0.43	2.13E-04	Uncontrolled emission factors (criteria and HAP/TAP) for wood combustion from AP-42; Compilation of Air Pollutant Emission Factors Vol. 1 - Stationary Sources USEPA, 5th ed. Section 1.6, 9/04
B0004	N/A	EP-B0004	Ethyl benzene	3.21E-02	281.61	1.41E-01	Uncontrolled emission factors (criteria and HAP/TAP) for wood combustion from AP-42; Compilation of Air Pollutant Emission Factors Vol. 1 - Stationary Sources USEPA, 5th ed. Section 1.6, 9/05
B0004	N/A	EP-B0004	Ethylene dichloride (1,2-dichloroethane)	3.01E-02	263.44	1.32E-01	Uncontrolled emission factors (criteria and HAP/TAP) for wood combustion from AP-42; Compilation of Air Pollutant Emission Factors Vol. 1 - Stationary Sources USEPA, 5th ed. Section 1.6, 9/06
B0004	N/A	EP-B0004	Fluoroanthene	5.77E-10	0.00	2.53E-09	Uncontrolled and controlled emission factors (criteria and HAP/TAP) for natural gas combustion from Per AP-42, Section 1.4, 9/98.
B0004	N/A	EP-B0004	Fluorene	5.38E-10	0.00	2.36E-09	Uncontrolled and controlled emission factors (criteria and HAP/TAP) for natural gas combustion from Per AP-42, Section 1.4, 9/98.
B0004	N/A	EP-B0004	Formaldehyde	4.56E+00	39,970.13	2.00E+01	Uncontrolled emission factors (criteria and HAP/TAP) for wood combustion from AP-42; Compilation of Air Pollutant Emission Factors Vol. 1 - Stationary Sources USEPA, 5th ed. Section 1.6, 9/06
B0004	N/A	EP-B0004	Hexachlorodibenzo-p-dioxin 1,2,3,6,7,8	1.66E-03	14.53	7.27E-03	Uncontrolled emission factors (criteria and HAP/TAP) for wood combustion from AP-42; Compilation of Air Pollutant Emission Factors Vol. 1 - Stationary Sources USEPA, 5th ed. Section 1.6, 9/06
B0004	DSL-1	EP-B0004	Hydrogen chloride (hydrochloric acid)	2.07E+01	181,586.11	9.08E+01	lb/ MMBtu Emission Factor provided from ESI Inc of Tennessee for Controlled Emission rate after dry sorbent injection.
B0004	N/A	EP-B0004	Hydrogen fluoride	9.23E+01	808,486.68	4.04E+02	Hydrogen fluoride emissions are assumed to be 50% of the Hydrogen chloride emissions.
B0004	N/A	EP-B0004	Indo(1,2,3-cd)pyrene	3.46E-10	0.00	1.52E-09	Uncontrolled and controlled emission factors (criteria and HAP/TAP) for natural gas combustion from Per AP-42, Section 1.4, 9/98.
B0004	N/A	EP-B0004	Lead and Lead compounds	4.98E-02	436.04	2.18E-01	Uncontrolled emission factors (criteria and HAP/TAP) for wood combustion from AP-42; Compilation of Air Pollutant Emission Factors Vol. 1 - Stationary Sources USEPA, 5th ed. Section 1.6, 9/06
B0004	N/A	EP-B0004	Manganese & compounds	1.66E+00	14,534.59	7.27E+00	Uncontrolled emission factors (criteria and HAP/TAP) for wood combustion from AP-42; Compilation of Air Pollutant Emission Factors Vol. 1 - Stationary Sources USEPA, 5th ed. Section 1.6, 9/06
B0004	ACT-1	EP-B0004	Mercury, vapor (Include in Mercury & Compds)	3.10E-03	27.16	1.36E-02	lb/ MMBtu Emission Factor provided from ESI Inc of Tennessee for Controlled Emission rate after Activated Carbon Injection.
B0004	N/A	EP-B0004	Methyl bromide (bromomethane)	1.56E-02	136.26	6.81E-02	Uncontrolled emission factors (criteria and HAP/TAP) for wood combustion from AP-42; Compilation of Air Pollutant Emission Factors Vol. 1 - Stationary Sources USEPA, 5th ed. Section 1.6, 9/06
B0004	N/A	EP-B0004	Methyl chloride (chloromethane)	2.39E-02	208.93	1.04E-01	Uncontrolled emission factors (criteria and HAP/TAP) for wood combustion from AP-42; Compilation of Air Pollutant Emission Factors Vol. 1 - Stationary Sources USEPA, 5th ed. Section 1.6, 9/07
B0004	N/A	EP-B0004	Methyl chloroform (1,1,1 trichloroethane)	3.21E-02	281.61	1.41E-01	Uncontrolled emission factors (criteria and HAP/TAP) for wood combustion from AP-42; Compilation of Air Pollutant Emission Factors Vol. 1 - Stationary Sources USEPA, 5th ed. Section 1.6, 9/08
B0004	N/A	EP-B0004	Methyl ethyl ketone	5.60E-03	49.05	2.45E-02	Uncontrolled emission factors (criteria and HAP/TAP) for wood combustion from AP-42; Compilation of Air Pollutant Emission Factors Vol. 1 - Stationary Sources USEPA, 5th ed. Section 1.6, 9/09
B0004	N/A	EP-B0004	Methylene chloride (dichloromethane)	3.01E-01	2,634.39	1.32E+00	Uncontrolled emission factors (criteria and HAP/TAP) for wood combustion from AP-42; Compilation of Air Pollutant Emission Factors Vol. 1 - Stationary Sources USEPA, 5th ed. Section 1.6, 9/10
B0004	N/A	EP-B0004	Naphthalene	1.01E-01	881.16	4.41E-01	Uncontrolled emission factors (criteria and HAP/TAP) for wood combustion from AP-42; Compilation of Air Pollutant Emission Factors Vol. 1 - Stationary Sources USEPA, 5th ed. Section 1.6, 9/11
B0004	N/A	EP-B0004	Nickel metal (Component of Nickel & Compounds)	3.42E-02	299.78	1.50E-01	Uncontrolled emission factors (criteria and HAP/TAP) for wood combustion from AP-42; Compilation of Air Pollutant Emission Factors Vol. 1 - Stationary Sources USEPA, 5th ed. Section 1.6, 9/12
B0004	N/A	EP-B0004	Nitrophenol, 4-	1.14E-04	1.00	5.00E-04	Uncontrolled emission factors (criteria and HAP/TAP) for wood combustion from AP-42; Compilation of Air Pollutant Emission Factors Vol. 1 - Stationary Sources USEPA, 5th ed. Section 1.6, 9/13
B0004	N/A	EP-B0004	Pentachlorophenol	5.29E-05	0.46	2.32E-04	Uncontrolled emission factors (criteria and HAP/TAP) for wood combustion from AP-42; Compilation of Air Pollutant Emission Factors Vol. 1 - Stationary Sources USEPA, 5th ed. Section 1.6, 9/14
B0004	N/A	EP-B0004	Perchloroethylene (tetrachloroethylene)	3.94E-02	345.20	1.73E-01	Uncontrolled emission factors (criteria and HAP/TAP) for wood combustion from AP-42; Compilation of Air Pollutant Emission Factors Vol. 1 - Stationary Sources USEPA, 5th ed. Section 1.6, 9/15
B0004	N/A	EP-B0004	Phenanthrene	3.27E-09	0.00	1.43E-08	Uncontrolled and controlled emission factors (criteria and HAP/TAP) for natural gas combustion from Per AP-42, Section 1.4, 9/98.
B0004	N/A	EP-B0004	Phenol	5.29E-02	463.29	2.32E-01	Uncontrolled emission factors (criteria and HAP/TAP) for wood combustion from AP-42; Compilation of Air Pollutant Emission Factors Vol. 1 - Stationary Sources USEPA, 5th ed. Section 1.6, 9/15

Emission Unit	Air Pollution Control Device ID	Stack ID	Pollutant Emitted	Potential Emission Rates			Method of Determination
				lb/hr	lb/yr	tpy	
B0004	N/A	EP-B0004	Phosphorus Metal, Yellow or White	2.80E-02	245.27	1.23E-01	Uncontrolled emission factors (criteria and HAP/TAP) for wood combustion from AP-42; Compilation of Air Pollutant Emission Factors Vol. 1 - Stationary Sources USEPA, 5th ed. Section 1.6, 9/16
B0004	N/A	EP-B0004	Polychlorinated biphenyls	8.45E-06	0.07	3.70E-05	Uncontrolled emission factors (criteria and HAP/TAP) for wood combustion from AP-42; Compilation of Air Pollutant Emission Factors Vol. 1 - Stationary Sources USEPA, 5th ed. Section 1.6, 9/17
B0004	N/A	EP-B0004	Polycyclic Organic Matter	1.30E-01	1,135.52	5.68E-01	Uncontrolled emission factors (criteria and HAP/TAP) for wood combustion from AP-42; Compilation of Air Pollutant Emission Factors Vol. 1 - Stationary Sources USEPA, 5th ed. Section 1.6, 9/18
B0004	N/A	EP-B0004	Propionaldehyde	6.33E-02	554.13	2.77E-01	Uncontrolled emission factors (criteria and HAP/TAP) for wood combustion from AP-42; Compilation of Air Pollutant Emission Factors Vol. 1 - Stationary Sources USEPA, 5th ed. Section 1.6, 9/19
B0004	N/A	EP-B0004	Propylene dichloride (1,2 dichloropropane)	3.42E-02	299.78	1.50E-01	Uncontrolled emission factors (criteria and HAP/TAP) for wood combustion from AP-42; Compilation of Air Pollutant Emission Factors Vol. 1 - Stationary Sources USEPA, 5th ed. Section 1.6, 9/20
B0004	N/A	EP-B0004	Pyrene	9.61E-10	0.00	4.21E-09	Uncontrolled and controlled emission factors (criteria and HAP/TAP) for natural gas combustion from Per AP-42, Section 1.4, 9/98
B0004	N/A	EP-B0004	Selenium compounds	2.90E-03	25.44	1.27E-02	Uncontrolled emission factors (criteria and HAP/TAP) for wood combustion from AP-42; Compilation of Air Pollutant Emission Factors Vol. 1 - Stationary Sources USEPA, 5th ed. Section 1.6, 9/20
B0004	N/A	EP-B0004	Silver	1.76E+00	15,443.00	7.72E+00	Uncontrolled emission factors (criteria and HAP/TAP) for wood combustion from AP-42; Compilation of Air Pollutant Emission Factors Vol. 1 - Stationary Sources USEPA, 5th ed. Section 1.6, 9/21
B0004	N/A	EP-B0004	Styrene	1.97E+00	17,259.83	8.63E+00	Uncontrolled emission factors (criteria and HAP/TAP) for wood combustion from AP-42; Compilation of Air Pollutant Emission Factors Vol. 1 - Stationary Sources USEPA, 5th ed. Section 1.6, 9/22
B0004	N/A	EP-B0004	Tetrachlorodibenzo-p-dioxin, 2,3,7,8-	8.92E-09	0.00	3.91E-08	Uncontrolled emission factors (criteria and HAP/TAP) for wood combustion from AP-42; Compilation of Air Pollutant Emission Factors Vol. 1 - Stationary Sources USEPA, 5th ed. Section 1.6, 9/23
B0004	N/A	EP-B0004	Toluene	9.54E-01	8,357.39	4.18E+00	Uncontrolled emission factors (criteria and HAP/TAP) for wood combustion from AP-42; Compilation of Air Pollutant Emission Factors Vol. 1 - Stationary Sources USEPA, 5th ed. Section 1.6, 9/24
B0004	N/A	EP-B0004	Trichloroethylene	3.11E-02	272.52	1.36E-01	Uncontrolled emission factors (criteria and HAP/TAP) for wood combustion from AP-42; Compilation of Air Pollutant Emission Factors Vol. 1 - Stationary Sources USEPA, 5th ed. Section 1.6, 9/25
B0004	N/A	EP-B0004	Trichlorofluoromethane (CFC 111)	4.25E-02	372.45	1.86E-01	Uncontrolled emission factors (criteria and HAP/TAP) for wood combustion from AP-42; Compilation of Air Pollutant Emission Factors Vol. 1 - Stationary Sources USEPA, 5th ed. Section 1.6, 9/26
B0004	N/A	EP-B0004	Trichlorophenol, 2,4,6-	2.28E-05	0.20	9.99E-05	Uncontrolled emission factors (criteria and HAP/TAP) for wood combustion from AP-42; Compilation of Air Pollutant Emission Factors Vol. 1 - Stationary Sources USEPA, 5th ed. Section 1.6, 9/27
B0004	N/A	EP-B0004	Vinyl chloride	1.87E-02	163.51	8.18E-02	Uncontrolled emission factors (criteria and HAP/TAP) for wood combustion from AP-42; Compilation of Air Pollutant Emission Factors Vol. 1 - Stationary Sources USEPA, 5th ed. Section 1.6, 9/28
B0004	N/A	EP-B0004	Xylene, o-	2.59E-02	227.10	1.14E-01	Uncontrolled emission factors (criteria and HAP/TAP) for wood combustion from AP-42; Compilation of Air Pollutant Emission Factors Vol. 1 - Stationary Sources USEPA, 5th ed. Section 1.6, 9/29
B0004	N/A	EP-B0004	Total HAPs	1.34E+02	1,170,110.16	585.1	Sum of all HAPs

Facility Name: The Procter & Gamble Paper Products Company **Date of Application:** June 2013

FORM 5.00 MONITORING INFORMATION

Emission Unit ID/ APCD ID	Emission Unit/APCD Name	Monitored Parameter		Monitoring Frequency
		Parameter	Units	

Comments:

See Table 4-2 of main report for a detailed summary of this information

Facility Name: The Procter & Gamble Paper Products Company **Date of Application:** June 2013

FORM 6.00 – FUGITIVE EMISSION SOURCES[illegible]

Facility Name: The Procter & Gamble Paper Products Company **Date of Application:** June 2013

FORM 7.00 – AIR MODELING INFORMATION: Stack Data

Stack ID	Emission Unit ID(s)	Stack Information			Dimensions of largest Structure Near Stack		Exit Gas Conditions at Maximum Emission Rate			
		Height Above Grade (ft)	Inside Diameter (ft)	Exhaust Direction	Height (ft)	Longest Side (ft)	Velocity (ft/sec)	Temperature (°F)	Flow Rate (acfm)	
									Average	Maximum
See	Modeling	Report for	Source	and Building	parameters					

NOTE: If emissions are not vented through a stack, describe point of discharge below and, if necessary, include an attachment. List the attachment in Form 1.00 *General Information*, Item 16.

Date of Application: June 2013

[illegible]

APPENDIX B: NEW EMISSIONS SUPPORTING CALCULATIONS

APPENDIX B
COGENERATION BIOMASS BOILER

Heat Input (MMBtu/hr)	1,037.00																		
Operating Schedule (hrs/yr)	8760																		
Heat Input (MMBtu/yr)	9,084,120																		
Baghouse Particulate / Metal HAP Control Efficiency	95.00%	supplied from ESI Inc. of Tennessee																	
SNCR NOx Control Efficiency	90.00%	supplied from ESI Inc. of Tennessee																	
Trona/Bicarbonate SOx Control Efficiency	92.30%	supplied from ESI Inc. of Tennessee																	
Trona/Bicarbonate HCl Control Efficiency	88.77%	supplied from ESI Inc. of Tennessee																	
Activated Carbon Hg Control Efficiency	92.70%	supplied from ESI Inc. of Tennessee																	
Biomass Feed (Heat Input Basis) (%)	100.00%																		
Biomass Usage (tons/yr) =	983,130																		
Biomass Heating Value (BTU/lb) =	4,620	from Sterling Plant Emission calcs																	
Natural Gas Burner Heat Input (MMBtu/hr)	200.00																		
Hours to Startup =	8.00	hrs																	
No. of Startups per year =	3																		
Max Hours of Startup per year =	24.00																		
Natural Gas Usage (scf/yr)=	4,705,882	196,078.43																	
Natural Gas Heating Value (BTU/scf)=	1,020																		

Pollutant	Pollutant Type	Emission Factors							Emissions				Worst Case Emission Factor	Total Uncontrolled Total			Maximum Controlled Total ⁷		
		Biomass				Natural Gas Startup			Biomass Combustion Emissions		Natural Gas Startup Emissions			lb/hr	lb/yr	tpy	lb/hr	lb/yr	tpy
		lb/MMBtu Uncontrolled	% Efficiency	lb/MMBtu Controlled	Ref.	lb/10 ⁶ scf Uncontrolled	lb/MMBtu Uncontrolled	Ref.	lb/hr Uncontrolled	Controlled	lb/hr Uncontrolled	Controlled							
PSD-Regulated Pollutants																			
Filterable Particulate Matter (PM)	PSD	1.280	99.4%	0.0098	5			2	1.33E+03	1.02E+01				1,327.36	11,627,673.60	5813.8	10.16	89,024.38	44.51
Filterable Particulate Matter<10 microns (PM ₁₀)	PSD	0.528	98.3%	0.0098	5			2	5.48E+02	1.02E+01				547.54	4,796,415.36	2398.2	10.16	89,024.38	44.51
Filterable Particulate Matter<2.5 microns (PM _{2.5})	PSD	0.184	95.1%	0.0098	5			2	1.91E+02	1.02E+01				190.81	1,671,478.08	835.7	10.16	89,024.38	44.51
Condensable Particulate Matter (PM _{Cond})	PSD	0.0162		0.0162	5			2	1.68E+01	1.68E+01				16.80	147,162.74	73.58	16.80	147,162.74	73.58
Total Particulate Matter (PM)	PSD	1.296	99.4%	0.0260	3,5	7.600	7.45E-03	3	1.34E+03	2.70E+01	1.49E+00	1.49E+00	Biomass	1,344.16	11,774,836.34	5887.4	26.96	236,187	118.09
Total Particulate Matter<10 microns (PM ₁₀)	PSD	0.544	98.3%	0.0260	3,5	7.600	7.45E-03	3	5.64E+02	2.70E+01	1.49E+00	1.49E+00	Biomass	564.34	4,943,578.10	2471.8	26.96	236,187	118.09
Total Particulate Matter<2.5 microns (PM _{2.5})	PSD	0.200	95.1%	0.0260	3,5	7.600	7.45E-03	3	2.08E+02	2.70E+01	1.49E+00	1.49E+00	Biomass	207.61	1,818,640.82	909.3	26.96	236,187	118.09
Sulfur Dioxide (SO ₂)	PSD	0.260	92.3%	0.0200	5	6.00E-01	5.88E-04	2	2.70E+02	2.08E+01	1.18E-01	1.18E-01	Biomass	269.62	2,361,871.20	1180.94	20.76	181,864	90.93
Nitrogen Oxides (NO _x)	PSD	0.200	62.5%	0.075	5		1.00E-01	5	2.07E+02	7.78E+01	2.00E+01	2.00E+01	Biomass	207.40	1,816,824.00	908.4	77.78	681,309	340.7
Carbon Monoxide (CO)	PSD/ TAP	0.100		0.100	5		1.20E-01	5	1.04E+02	1.04E+02	2.40E+01	2.40E+01	Biomass	103.70	908,412.00	454.2	103.70	908,412	454.2
Volatile Organic Compounds (VOC)	PSD	0.007		0.007	5	5.5	5.39E-03	2	7.26E+00	7.26E+00	1.08E+00	1.08E+00	Biomass	7.26	63,588.84	31.79	7.26	63,589	31.79
Lead	PSD/TAP	4.80E-05		4.80E-05	1	0.0005	4.90E-07		4.98E-02	4.98E-02	9.80E-05	9.80E-05	Biomass	4.98E-02	436.04	0.22	0.05	436	0.22
GHG																			
Carbon Dioxide (CO2)		195.00		1.95E+02	1		116.89	2	2.02E+05	2.02E+05	2.34E+04	2.34E+04	Biomass	2.02E+05	1,771,964,468	885,982	2.02E+05	1,771,964,468	885,982
Methane (CH4)		0.021		2.10E-02	1		0.0022	2	2.18E+01	2.18E+01	4.41E-01	4.41E-01	Biomass	2.18E+01	190,777	95.39	2.18E+01	190,777	95.39
Nitrous Oxide (N2O)		0.013		1.30E-02	1		0.00022	2	1.35E+01	1.35E+01	4.41E-02	4.41E-02	Biomass	1.35E+01	118,095	59.05	1.35E+01	118,095	59.05
CO2e				199.47	4		117.004		2.07E+05	2.07E+05	2.34E+04	2.34E+04	Biomass	2.07E+05	1,812,580,118	906,290	2.07E+05	1,812,580,118	906,290
CO2e biomass deferral				4.47	4		117.0037		4.64E+03	4.64E+03	2.34E+04	2.34E+04	Nat Gas	2.34E+04	41,176,718	20,588	2.34E+04	41,176,718	20,588
Hazardous Air Pollutants																			
Acetaldehyde	HAP/TAP	8.30E-04		8.30E-04	1				8.61E-01	8.61E-01				8.61E-01	7,539.82	3.77E+00	8.61E-01	7,539.82	3.77E+00
Acetophenone	HAP/TAP	3.20E-09		3.20E-09	1				3.32E-06	3.32E-06				3.32E-06	0.03	1.45E-05	3.32E-06	0.03	1.45E-05
Acenaphthene	HAP			0.00E+00		1.80E-06	1.76E-09	2			3.53E-07	3.53E-07	Nat Gas	3.53E-07	0.00	1.55E-06	3.53E-07	0.00	1.55E-06
Acenaphthylene	HAP			0.00E+00		1.80E-06	1.76E-09	2			3.53E-07	3.53E-07	Nat Gas	3.53E-07	0.00	1.55E-06	3.53E-07	0.00	1.55E-06
Acrolein	HAP/TAP	4.00E-03		4.00E-03	1				4.15E+00	4.15E+00			Biomass	4.15E+00	36,336.48	1.82E+01	4.15E+00	36,336.48	1.82E+01
Ammonia	TAP				7				2.16E+01	2.16E+01			Biomass	2.16E+01	189,500.80	9.48E+01	2.16E+01	189,500.80	9.48E+01
Antimony & Compounds	HAP/TAP	7.90E-06		7.90E-06	1				8.19E-03	8.19E-03			Biomass	8.19E-03	71.76	3.59E-02	8.19E-03	71.76	3.59E-02
Arsenic & Compounds	HAP/TAP	2.20E-05		2.20E-05	1	1.96E-07	1.92E-10	2	2.28E-02	2.28E-02	3.84E-08	3.84E-08	Biomass	2.28E-02	199.85	9.99E-02	2.28E-02	199.85	9.99E-02
Benzene	HAP/TAP	4.20E-03		4.20E-03	1	2.06E-06	2.02E-09	2	4.36E+00	4.36E+00	4.04E-07	4.04E-07	Biomass	4.36E+00	38,153.30	1.91E+01	4.36E+00	38,153.30	1.91E+01
Benzo(b,k)fluoranthene	HAP			1.76E-09		1.73E-12	1.73E-12	2			3.46E-10	3.46E-10	Nat Gas	3.46E-10	0.00	1.52E-09	3.46E-10	0.00	1.52E-09
Benzo(g,h,i)perylene	HAP			1.18E-09		1.15E-12	1.15E-12	2			2.31E-10	2.31E-10	Nat Gas	2.31E-10	0.00	1.01E-09	2.31E-10	0.00	1.01E-09
Benzo(a)pyrene	HAP	2.60E-06		2.60E-06	1				2.70E-03	2.70E-03			Biomass	2.70E-03	23.62	1.18E-02	2.70E-03	23.62	1.18E-02
Beryllium metal	HAP/TAP	1.10E-06		1.10E-06	1	1.18E-08	1.15E-11	2	1.14E-03	1.14E-03	2.31E-09	2.31E-09	Biomass	1.14E-03	9.99	5.00E-03	1.14E-03	9.99	5.00E-03
Cadmium Metal	HAP/TAP	4.10E-06		4.10E-06	1	1.08E-06	1.06E-09	2	4.25E-03	4.25E-03	2.11E-07	2.11E-07	Biomass	4.25E-03	37.24	1.86E-02	4.25E-03	37.24	1.86E-02
Carbon tetrachloride	HAP	4.50E-05		4.50E-05	1				4.67E-02	4.67E-02			Biomass	4.67E-02	408.79	2.04E-01	4.67E-02	408.79	2.04E-01
Chlorine	HAP	7.90E-04		7.90E-04	1				8.19E-01	8.19E-01			Biomass	8.19E-01	7,176.45	3.59E+00	8.19E-01	7,176.45	3.59E+00
Chlorobenzene	HAP	3.30E-05		3.30E-05	1				3.42E-02	3.42E-02			Biomass	3.42E-02	299.78	1.50E-01	3.42E-02	299.78	1.50E-01
Chloroform	HAP	2.80E-05		2.80E-05	1				2.90E-02	2.90E-02			Biomass	2.90E-02	254.36	1.27E-01	2.90E-02	254.36	1.27E-01
Chromium–Other compds	HAP/TAP	1.75E-05		1.75E-05	1				1.81E-02	1.81E-02			Biomass	1.81E-02	158.97	7.95E-02	1.81E-02	158.97	

Pollutant	Pollutant Type	Emission Factors							Emissions				Worst Case Emission Factor	Total Uncontrolled Total			Maximum Controlled Total ⁷		
		Biomass				Natural Gas Startup			Biomass Combustion Emissions		Natural Gas Startup Emissions			lb/hr	lb/yr	tpy	lb/hr	lb/yr	tpy
		lb/MMBtu Uncontrolled	% Efficiency	lb/MMBtu Controlled	Ref.	lb/10 ⁶ scf Uncontrolled	lb/MMBtu Uncontrolled	Ref.	Uncontrolled	Controlled	Uncontrolled	Controlled							
Mercury, vapor (Include in Mercury & Compds)	HAP/TAP	1.10E-05	92.7%	8.00E-07	5	3.73E-07	3.65E-10	2	1.14E-02	8.30E-04	7.30E-08	7.30E-08	Biomass	1.14E-02	99.93	5.00E-02	8.30E-04	7.27	3.63E-03
Methyl bromide (bromomethane)	HAP	1.50E-05		1.50E-05	1				1.56E-02	1.56E-02			Biomass	1.56E-02	136.26	6.81E-02	136.26	6.81E-02	
Methyl chloride (chloromethane)	HAP	2.30E-05		2.30E-05	1				2.39E-02	2.39E-02			Biomass	2.39E-02	208.93	1.04E-01	2.39E-02	208.93	1.04E-01
Methyl chloroform (1,1,1 trichloroethane)	HAP	3.10E-05		3.10E-05	1				3.21E-02	3.21E-02			Biomass	3.21E-02	281.61	1.41E-01	3.21E-02	281.61	1.41E-01
Methyl ethyl ketone	HAP	5.40E-06		5.40E-06	1				5.60E-03	5.60E-03			Biomass	5.60E-03	49.05	2.45E-02	5.60E-03	49.05	2.45E-02
Methylene chloride (dichloromethane)	HAP	2.90E-04		2.90E-04	1				3.01E-01	3.01E-01			Biomass	3.01E-01	2,634.39	1.32E+00	3.01E-01	2,634.39	1.32E+00
Naphthalene	HAP	9.70E-05		9.70E-05	1	5.98E-07	5.86E-10	2	1.01E-01	1.01E-01	1.17E-07	1.17E-07	Biomass	1.01E-01	881.16	4.41E-01	1.01E-01	881.16	4.41E-01
Nickel metal (Component of Nickel & Compounds)	HAP/TAP	3.30E-05		3.30E-05	1				3.42E-02	3.42E-02			Biomass	3.42E-02	299.78	1.50E-01	3.42E-02	299.78	1.50E-01
Nitrophenol, 4-	HAP	1.10E-07		1.10E-07	1				1.14E-04	1.14E-04			Biomass	1.14E-04	1.00	5.00E-04	1.14E-04	1.00	5.00E-04
Pentachlorophenol	HAP	5.10E-08		5.10E-08	1				5.29E-05	5.29E-05			Biomass	5.29E-05	0.46	2.32E-04	5.29E-05	0.46	2.32E-04
Perchloroethylene (tetrachloroethylene)	HAP	3.80E-05		3.80E-05	1				3.94E-02	3.94E-02			Biomass	3.94E-02	345.20	1.73E-01	3.94E-02	345.20	1.73E-01
Phenanthrene	HAP					1.67E-08	1.63E-11	2			3.27E-09	3.27E-09	Nat Gas	3.27E-09	0.00	1.43E-08	3.27E-09	0.00	1.43E-08
Phenol	HAP	5.10E-05		5.10E-05	1				5.29E-02	5.29E-02			Biomass	5.29E-02	463.29	2.32E-01	5.29E-02	463.29	2.32E-01
Phosphorus Metal, Yellow or White	HAP/TAP	2.70E-05		2.70E-05	1				2.80E-02	2.80E-02			Biomass	2.80E-02	245.27	1.23E-01	2.80E-02	245.27	1.23E-01
Polychlorinated biphenyls	HAP	8.15E-09		8.15E-09	1				8.45E-06	8.45E-06			Biomass	8.45E-06	0.07	3.70E-05	8.45E-06	0.07	3.70E-05
Polycyclic Organic Matter	HAP	1.25E-04		1.25E-04	1				1.30E-01	1.30E-01			Biomass	1.30E-01	1,135.52	5.68E-01	1.30E-01	1,135.52	5.68E-01
Propionaldehyde	HAP	6.10E-05		6.10E-05	1				6.33E-02	6.33E-02			Biomass	6.33E-02	554.13	2.77E-01	6.33E-02	554.13	2.77E-01
Propylene dichloride (1,2 dichloropropane)	HAP	3.30E-05		3.30E-05	1				3.42E-02	3.42E-02			Biomass	3.42E-02	299.78	1.50E-01	3.42E-02	299.78	1.50E-01
Pyrene	HAP					4.90E-09	4.81E-12	2			9.61E-10	9.61E-10	Nat Gas	9.61E-10	0.00	4.21E-09	9.61E-10	0.00	4.21E-09
Selenium compounds	HAP/TAP	2.80E-06		2.80E-06	1	2.35E-08	2.31E-11	2	2.90E-03	2.90E-03	4.61E-09	4.61E-09	Biomass	2.90E-03	25.44	1.27E-02	2.90E-03	25.44	1.27E-02
Silver	TAP	1.70E-03		1.70E-03	1				1.76E+00	1.76E+00			Biomass	1.76E+00	15,443.00	7.72E+00	1.76E+00	15,443.00	7.72E+00
Styrene	HAP/TAP	1.90E-03		1.90E-03	1				1.97E+00	1.97E+00			Biomass	1.97E+00	17,259.83	8.63E+00	1.97E+00	17,259.83	8.63E+00
Tetrachlorodibenzo-p-dioxin, 2,3,7,8-	HAP	8.60E-12		8.60E-12	1				8.92E-09	8.92E-09			Biomass	8.92E-09	0.00008	3.91E-08	8.92E-09	0.00	3.91E-08
Toluene	HAP	9.20E-04		9.20E-04	1	3.33E-06	3.27E-09	2	9.54E-01	9.54E-01	6.54E-07	6.54E-07	Biomass	9.54E-01	8,357.39	4.18E+00	9.54E-01	8,357.39	4.18E+00
Trichloroethylene	HAP	3.00E-05		3.00E-05	1				3.11E-02	3.11E-02			Biomass	3.11E-02	272.52	1.36E-01	3.11E-02	272.52	1.36E-01
Trichlorofluoromethane (CFC 111)	HAP	4.10E-05		4.10E-05	1				4.25E-02	4.25E-02			Biomass	4.25E-02	372.45	1.86E-01	4.25E-02	372.45	1.86E-01
Trichlorophenol, 2,4,6-	HAP	2.20E-08		2.20E-08	1				2.28E-05	2.28E-05			Biomass	2.28E-05	0.20	9.99E-05	2.28E-05	0.20	9.99E-05
Vinyl chloride	HAP	1.80E-05		1.80E-05	1				1.87E-02	1.87E-02			Biomass	1.87E-02	163.51	8.18E-02	1.87E-02	163.51	8.18E-02
Xylene, o-	HAP	2.50E-05		2.50E-05	1				2.59E-02	2.59E-02			Biomass	2.59E-02	227.10	1.14E-01	2.59E-02	227.10	1.14E-01
* Highest HAP														1.85E+02	1,616,973.36	808.5	9.23E+01	808,486.68	404.2
* Total HAPs														2.97E+02	2,605,570.18	1302.8	1.34E+02	1,170,090.27	585.0

¹ Uncontrolled emission factors (criteria and HAP/TAP) for wood combustion from AP-42; Compilation of Air Pollutant Emission Factors Vol. 1 - Stationary Sources USEPA, 5th ed. Section 1.6, 9/03

² Uncontrolled and controlled emission factors (criteria and HAP/TAP) for natural gas combustion from Per AP-42, Section 1.4, 9/98.

³ Controlled PM emission factor is Boiler MACT Emission limit for biomas fluid bed boilers of 0.0098 + Condensible PM portion of 0.0162 lb/MMBtu which is 95% of the AP-42 condensible factor. PM=PM10=PM2.5 for conservatism and since speciation for biomass is unknown.

⁴ CO2e does not have an emission factor. CO2e is the sum of Carbon Dioxide, Methane, and Nitrous Oxide.

⁵ Provided from ESI Inc of Tennessee.

⁶ Hydrogen fluoride emissions are assumed to be 50% of the Hydrogen chloride emissions.

⁷ Ammonia emissions are calculated from the ammonia slip calculation in a separate spreadsheet provided later in this appendix.

APPENDIX B AMMONIA SLIP

Maximum Exhaust Flow Rate (ACFM):	408,600
Excess O2 in Dry Exhaust Stream:	5.00 %
NH ₃ ppm at 5% O2	20.00

lb/hr NH₃ = 20 ppm (NH₃/exhaust) * 10⁻⁶ lbs exhaust * 408600 ACFM * 1 lbmol / 386 scf * 17.03 lb/lbmol * 60 min/hr

lb/hr NH₃ = **21.63**

APPENDIX B SORBENT SILO

Potential Annual Hours of Operation:	300 hr/yr
Estimated Air Flow Rate	200 SCFM
Emission Rate for Bagfilter:	0.005 gr/ft ³
Percentage of TSP Classified as PM ₁₀ / PM _{2.5} :	100% Conservative Assumption

The following equation presents the calculation to determine PM emissions from the sodium bicarbonate/ trona silo

$$PM \left(\frac{lb}{hr} \right) = 1000 \frac{ft^3}{min} * 60 \frac{min}{hr} * 0.01 \frac{gr}{ft^3} * \frac{1 lb}{7,000 gr}$$

$$= 8.57 E - 02 \frac{lb}{hr}$$

Pollutant	Emission Factor		Potential Emission Rate	
	Value	Units	(lb/hr)	(ton/yr)
Particulate Matter (TSP)	8.57E-03	lb/hr	8.57E-03	1.29E-03
PM ₁₀	8.57E-03	lb/hr	8.57E-03	1.29E-03
PM _{2.5}	8.57E-03	lb/hr	8.57E-03	1.29E-03

APPENDIX B FLYASH SILO

Potential Annual Hours of Operation:	8,760 hr/yr
Estimated Air Flow Rate	1,000 SCFM
Emission Rate for Bagfilter:	0.005 gr/ft ³
Percentage of TSP Classified as PM ₁₀ / PM _{2.5} :	100% Conservative Assumption

The following equation presents the calculation to determine PM emissions from the flyash silo.

$$\begin{aligned}
 \text{PM} \left(\frac{\text{lb}}{\text{hr}} \right) &= 1000 \frac{\text{ft}^3}{\text{min}} * 60 \frac{\text{min}}{\text{hr}} * 0.01 \frac{\text{gr}}{\text{ft}^3} * \frac{1 \text{ lb}}{7,000 \text{ gr}} \\
 &= 8.57 \text{ E} - 02 \frac{\text{lb}}{\text{hr}}
 \end{aligned}$$

Pollutant	Emission Factor		Potential Emission Rate	
	Value	Units	(lb/hr)	(ton/yr)
Particulate Matter (TSP)	4.29E-02	lb/hr	4.29E-02	1.88E-01
PM ₁₀	4.29E-02	lb/hr	4.29E-02	1.88E-01
PM _{2.5}	4.29E-02	lb/hr	4.29E-02	1.88E-01

APPENDIX B ELECTRIC HOGGER

Hogger Throughput	245,782	tons dry wood
Moisture Content (approx.)	45%	of total weight ¹
Maximum Annual Operation	8,760	hours

Pollutant	Emission Factors (lb/dry wood tons)	Emissions ³	
		(lb/hr)	(tpy)
THC as Carbon ¹	0.35	8.602E+04	43.01
THC as alpha-Pinene ²	0.3973	9.764E+04	48.82
Methanol ⁴	0.0010	2.458E+02	0.12

1. VOC emission factor provided by SCDHEC in NCASI Technical Bulletin No. 723, Table 7 (Appendix H of this report); Emission factor for Ponderosa (Pine) wood used as it most coincides with Southern Yellow Pine.
2. The THC/VOC makeup of wood is primarily composed of terpenes (C₅H₈)_n [where n = 2, 3, or 4 typically] but to convert from carbon to the equivalent weight in THC/VOC, the assumption was that alpha-pinene (AP) would be the representative THC/VOC (molecular weight = 136.2 lb/lb-mol).
The following equation shows the conversion:

$$lb\ VOC/ODT = lb\ C/ODT * (136.2\ lb/mol\ AP / 12\ lb/mol\ C) * (1\ mol\ AP / 10\ mol\ C)$$
3. Short term emissions were based upon the annual throughput divided by the maximum hours of operation.
4. Emission factor obtained from available emissions factors for chippers in AP-42 Section 10.6.3, Table 7 and Section 10.6.4, Tables 7 and 9. Emission factors for Methanol are the same across all three tables.

**APPENDIX B
COOLING TOWER**

Unit	Flow Rate ^a (GPM)	Drift Loss ^b	Drift Rate (GPM)	Operating Hours per year	Total Drift Loss (gallons/year)	Water Density (lb/gal)	Total Drift Loss (ton drift/year)	TDS ^c (ppm)	Emissions PM (lbs/hr)	Emissions PM10 (lbs/hr)	Emissions PM2.5 (lbs/hr)	Emissions PM (lbs/yr)	Emissions PM ₁₀ (lbs/yr)	Emissions PM _{2.5} (lbs/yr)	Emissions PM (tpy)	Emissions PM ₁₀ (tpy) ^c	Emissions PM _{2.5} (tpy) ^c
ES-CT	26,000	0.0005%	0.13	8,760	68,328	8.270	282.54	784	0.05	0.03	0.0001	443.02	247.38	0.93	0.22	0.12	0.0005

Notes:

^aDesign flow rate.

^bManufacturer's guaranteed drift loss.

^cFacility supplied maximum total dissolved solids of inlet water of 98 ppm. Per Gil Waldman, Sterling, at 8 cycles of concentration, TDS is 784 ppm.

^dCalculated from *Calculating Realistic PM₁₀ Emissions from Cooling Towers* . At TDS of 2,500 ppm, 55.8% of PM is PM₁₀.

^eCalculated from *Calculating Realistic PM₁₀ Emissions from Cooling Towers* . At TDS of 2,500 ppm, 0.21% of PM is PM_{2.5}.

APPENDIX B STORAGE PILE

Emission Unit ID	Description	TSP Emission Factor ¹		VOC Emission Factor ³		Pile Shape	Cone Radius (ft)	Cone Height (ft)	Outer Surface Area of Storage Pile (ft ²)	PM Emissions		PM ₁₀ Emissions		PM _{2.5} Emissions		VOC Emissions ⁴	
		(lb/day/acre)	(lb/hr/ft ²)	(lb/day/acre)	(lb/hr/ft ²)					(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
SP01	Processed wood pile ²	0.54	5.12E-07	3.60	3.44E-06	Cone	190	90	125,492	0.064	0.282	0.032	0.141	0.0048	0.021	0.49	2.15
Total										0.064	0.282	0.032	0.141	0.0048	0.021	0.49	2.15

1. TSP emission factor based on U.S. EPA *Control of Open Fugitive Dust Sources*. Research Triangle Park, North Carolina, EPA-450/3-88-008. September 1988, Page 4-17.

$$E = 1.7 \left(\frac{s}{1.5} \right) \left(\frac{365-p}{235} \right) \left(\frac{f}{15} \right) (\text{lb / day / acre})$$

where:

where:

s, silt content of wood chips (%): 2
p, number of days with rainfall greater than 0.01 inch: 120
f (time that wind exceeds 5.36 m/s - 12 mph) (%): 3.4

ntent of wood chips (%): 2
ll greater than 0.01 inch: 120
5.36 m/s - 12 mph) (%): 3.4

Georgia Power Plant Mitchell Application #18663 submitted December 12, 2008.
Based on AP-42, Section 13.2.2, Figure 13.2.1-2.

Based on meteorological data averaged for 2007-2011, provided by Georgia EPD for Albany, GA.

PM₁₀/TSP ratio:

50%

PM₁₀/TSP ratio:

50%

PM₁₀ is assumed to equal 50% of TSP based on U.S. EPA *Control of Open Fugitive Dust Sources*, Research Triangle Park, North Carolina, EPA-450/3-88-008. September 1988.

PM_{2.5}/TSP ratio:

7.5%

PM_{2.5}/TSP ratio:

7.5%

PM_{2.5} is assumed to equal 7.5 % of TSP U.S. EPA Background Document for Revisions to Fine Fraction Ratios Used for AP-42 Fugitive Dust Emission Factors. November 2006.

2. The surface area is calculated based on the assumption that the pile geometry is accurately characterized by a cone for the pile, cone lateral surface area.

3. Emission factors obtained from NCASI document provided by SC DHEC for the calculation of fugitive VOC emissions from Douglas Fir wood storage piles. Emission factors ranged from 1.6 to 3.6 lb C/acre-day. P&G chose to employ the maximum emission factor for purposes of conservatism.

4. Emissions are calculated in tons of carbon per year by the following formula:

$$\text{tons C/year} = 5 \text{ acres} * 365 \text{ days} * 1.6 \text{ lb C/acre-day} / 2000 \text{ lb/ton}$$

The VOC makeup of wood is primarily composed of terpenes (C_nH₈)_n [where n = 2, 3, or 4 typically] but to convert from carbon to the equivalent weight in VOC, the assumption was that alpha-pinene (AP) would be the representative VOC (molecular weight = 136.2 lb/lb-mol). The following equation shows the conversion:

$$\text{ton VOC/year} = \text{ton C/year} * (136.2 \text{ lb/mol AP} / 12 \text{ lb/mol C}) * (1 \text{ mol AP} / 10 \text{ mol C})$$

APPENDIX C: EXISTING DECOMMISSIONED SOURCES ACTUAL EMISSION CALCULATIONS

APPENDIX C

P&G EXISTING BOILER NO. 2 ACTUAL EMISSIONS

CY2011 Emission Inventory Emission Factors

Annual		Summer		BTU/lb	5,742.20
Biomass (Tons)	Oil (1000 gal)	Biomass (Tons)	Oil (1000 gal)		
124,773.46	40.82	295.89	0.01		

Boiler 2

Emission Factors*

Fuel	Lead	CO	NOx	PM	PM-10	PM-2.5	SO2	VOC
Biomass (lb/MMBTU)	4.80E-05	0.60	0.22	0.02	0.01	0.01	0.03	0.02
Biomass (lb/ton)	5.51E-04	6.89	2.53	0.21	0.15	0.13	0.29	0.20
Oil (lb/1000 gal)	1.26E-03	5.00	24.00	3.30	2.34	1.72	53.38	0.25

*All EPA Emission Factors except PM from 2009 Stack Test

CY2011 Emission Inventory Actual Emissions

Emissions (tons)

Fuel	Lead	CO	NOx	PM	PM-10	PM-2.5	SO2	VOC
Biomass	3.44E-02	429.88	157.62	12.82	9.49	8.34	17.91	12.18
Oil	2.57E-05	0.10	0.49	0.07	0.05	0.04	1.09	0.005
Total	3.44E-02	429.99	158.11	12.89	9.54	8.37	19.00	12.19

APPENDIX C

P&G EXISTING BOILER NO. 2 ACTUAL EMISSIONS

CY2012 Emission Inventory Emission Factors

Annual		Summer		BTU/lb	5,742.20
Biomass (Tons)	Oil (1000 gal)	Biomass (Tons)	Oil (1000 gal)		
134,642.92	9.41	289.34	0.04		

Boiler 2

Emission Factors*

Fuel	Lead	CO	NOx	PM	PM-10	PM-2.5	SO2	VOC
Biomass (lb/MMBTU)	4.80E-05	0.60	0.22	0.02	0.01	0.01	0.03	0.02
Biomass (lb/ton)	5.51E-04	6.89	2.53	0.19	0.14	0.12	0.29	0.20
Oil (lb/1000 gal)	1.26E-03	5.00	24.00	3.30	2.34	1.72	53.38	0.25

*All EPA Emission Factors except PM from December 2011 Stack Test

CY2012 Emission Inventory Actual Emissions

Emissions (tons)

Fuel	Lead	CO	NOx	PM	PM-10	PM-2.5	SO2	VOC
Biomass	3.71E-02	463.89	170.09	12.68	9.38	8.24	19.33	13.14
Oil	5.93E-06	0.02	0.11	0.02	0.01	0.01	0.25	0.0012
Total	3.71E-02	463.91	170.21	12.70	9.39	8.25	19.58	13.14

APPENDIX C

P&G EXISTING STORAGE PILE ACTUAL EMISSIONS

Emission		TSP Emission Factor ¹		Pile	Cone Radius	Cone Height	Outer Surface Area of Storage Pile	PM Emissions		PM ₁₀ Emissions		PM _{2.5} Emissions	
Unit ID	Description	(lb/day/acre)	(lb/hr/ft ²)	Shape	(ft)	(ft)	(ft ²)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
	Existing Storage Pile	0.54	5.12E-07	Cone	207	26	135,672	0.070	0.304	0.035	0.152	0.005	0.023
Total								0.070	0.304	0.035	0.152	0.005	0.023

1. TSP emission factor based on U.S. EPA *Control of Open Fugitive Dust Sources*. Research Triangle Park, North Carolina, EPA-450/3-88-008. September 1988, Page 4-17.

$$E = 1.7 \left(\frac{s}{1.5} \right) \left(\frac{(365-p)}{235} \right) \left(\frac{f}{15} \right) (\text{lb/day/acre})$$

where:

s, silt content of wood chips (%):	2	Georgia Power Plant Mitchell Application #18663 submitted December 12, 2008.
p, number of days with rainfall greater than 0.01 inch:	120	Based on AP-42, Section 13.2.2, Figure 13.2.1-2.
f (time that wind exceeds 5.36 m/s - 12 mph) (%):	3.4	Based on meteorological data averaged for 2007-2011, provided by Georgia EPD for Albany, GA.
PM ₁₀ /TSP ratio:	50%	PM ₁₀ is assumed to equal 50% of TSP based on U.S. EPA <i>Control of Open Fugitive Dust Sources</i> , Research Triangle Park, North Carolina, EPA-450/3-88-008. September 1988.
PM _{2.5} /TSP ratio:	7.5%	PM _{2.5} is assumed to equal 7.5 % of TSP U.S. EPA Background Document for Revisions to Fine Fraction Ratios Used for AP-42 Fugitive Dust Emission Factors. November 2006.

2. The surface area is calculated for comparison to the new pile as if the pile geometry is accurately characterized by a cone for the pile, cone lateral surface area. An equivalent radius was calculated for the existing pile.

APPENDIX D: BACT SUPPORTING INFORMATION

Economic Feasibility Analysis Calculations

Table D-1. Cost Analysis Supporting Information for Tail-End SCR

Parameter	Boiler	Units	Note(s)
Maximum Boiler Capacity	1,037	MMBtu/hr	1
Uncontrolled Inlet Emissions	0.20	lb/MMBtu	1
Controlled Outlet Emissions	0.06	lb/MMBtu	2
Removal Efficiency	70	%	2
Pollutant Removed	636	tpy	3
SCR Inlet Airflow (before reheating)	446,423	acfm	4, 13
SCR Inlet Temperature (before reheating)	335	° F	5
SCR Inlet Temperature (after reheating)	470	° F	4
SCR Inlet Airflow (after reheating)	522,230	acfm	6, 13
Volume of Catalyst	6,250	ft ³	4
Catalyst Layers	4	layers	4
Ammonia Consumption (Pure)	69	lb/hr	4, 14
Water Consumption for Reagent Solution	35.00	gal/hr	4, 14
Reagent Solution Consumption	47	gal/hr	4, 14
Reagent Storage Capacity	24,000	gal	4, 14
Concentration of Stored Reagent Solution	19	% Reagent	7
Pressure Drop Across the SCR and Ductwork	15.0	inches of H ₂ O	4
Electricity Usage	1,136	kWhr	4, 13
Catalyst Life	2.74	year	4
Reheating Needed	3.56	MMBtu/hr	4, 13
Natural Gas Heat Capacity	1,020.00	Btu/ ft3	8
NG Consumption for Gas Reheating	3,489.34	ft3/hr	9
Catalyst Cost, Initial	298.73	\$/ft ³	4
Catalyst Cost, Replacement	373.14	\$/ft ³	4
Ammonia Cost	0.53	\$/lb	10
Water Cost	0.0006	\$/gal	10
Electricity Cost	0.070	\$/kW-hr	10
Natural Gas Cost	6.88	\$/1000 ft3	11
SCR Equipment Life	20	years	12
Interest Rate	7.0	%	12

1. Potential inlet emissions based on maximum boiler capacity and emissions.
2. Based on vendor data. Efficiency calculated based on anticipated inlet emissions and outlet emissions.
3. Pollutant Removed (tpy) = (Uncontrolled Inlet Emissions - Controlled Outlet Emissions, lb/MMBtu) × (Maximum Boiler Capacity, MMBtu/hr) × (8,760 hr/yr) / (2000 lb/ton).
4. Value provided by Babcock Power for October 2009 PSD Permit Application for Oglethorpe Power Corporation, Warren County Biomass Energy Facility.
5. Value for designed stack outlet (after baghouse, based on no SCR).
6. Calculated value determined using flow rate before reheating and temperatures before and after reheating.
7. Design basis.
8. Per AP-42, Default value for Natural gas Heat Input value.
9. Calculated based on reheating needed (MMBtu/hr) and natural gas heat input.
10. Taken from Methodology for Estimating Control Costs for Industrial, Commercial, Institutional Boilers and Process Heaters Nation Emissions Standards for Hazardous Air Pollutants -- Major Source ERG Memo April 2010.
11. Energy Information Administration highest price for industrial natural gas between November 09 through April 10.
http://www.eia.gov/dnav/ng/ng_pri_sun
12. Based on example problem in OAQPS Manual, Section 4.2, Chapter 2, page 2-50.
13. Scaled 2009 Oglethorpe Warren Application natural gas consumption, electricity, and water linearly by multiplying Oglethorpe's consumption rates by the ratio of P&GPP Boiler of 1,037 MMBtu/hr divided by Oglethorpe's Boiler of 1,282 MMBTU/hr.
14. Scaled 2009 Oglethorpe Warren Application reagent consumption and catalyst based on NOx emissions reduction achieved by Oglethorpe's 1282 MMBTU/hr boiler versus the proposed NOx reduction for the P&GPP boiler of 1,037 MMBtu/hr. Oglethorpe Application specified NOx reduction from 0.18 lb/MMBTU to 0.06 lb/MMBTU with heat input of 1,282 MMBTU/hr, or 154 lb/hr NOx reduction. P&GPP is assuming reduction from 0.2 lb/MMBtu to 0.06 lb/MMBtu for its 1,037 MMBtu/hr boiler which is NOx reduction of 145.18 lb/hr. Therefore the ratio of NOx reduction for P&GPP divided by NOx reduction for Oglethorpe = 0.94

Table D-2. Cost Analysis for Tail-End SCR

Capital Cost	Boiler	OAQPS Notation ¹
<i>Purchased Equipment Costs</i>		
Total Equipment Cost ²	11,230,932	A
Instrumentation ³	1,123,093	$0.10 \times A$
Sales Tax ³	336,928	$0.03 \times A$
Freight ³	561,547	$0.05 \times A$
<i>Total Purchased Equipment Costs</i>	<i>13,252,499</i>	<i>$B = 1.18 \times A$</i>
<i>Direct Installation Costs⁴</i>		
Foundations and Supports	1,325,250	$0.10 \times B$
Handling and Erection	5,301,000	$0.40 \times B$
Electrical	530,100	$0.04 \times B$
Piping	265,050	$0.02 \times B$
Insulation	132,525	$0.01 \times B$
Painting	132,525	$0.01 \times B$
Site Preparation (Site Specific)	795,150	$0.06 \times B$
<i>Total Direct Installation Costs</i>	<i>8,481,600</i>	<i>$C = 0.64 \times B$</i>
<i>Indirect Installation Costs</i>		
General Facilities ⁵	4,346,820	$0.20 \times (B + C)$
Engineering and Home Office Fees	2,173,410	$0.10 \times (B + C)$
Process Contingencies	1,086,705	$0.05 \times (B + C)$
Construction Management ⁵	3,260,115	$0.15 \times (B + C)$
Owner's Cost ⁵	1,086,705	$0.05 \times (B + C)$
<i>Total Indirect Installation Costs</i>	<i>11,953,754</i>	<i>$D = 0.55 \times (B + C)$</i>
Project Contingency ⁵	6,737,571	$E = 0.20 \times (B + C + D)$
Total Plant Cost	40,425,424	$F = B + C + D + E$
Allowance for Funds During Construction ⁵	2,829,780	$G = 0.07 \times F$
Royalty Allowance	0	H
Preproduction Costs	865,104	$I = 0.02 \times (F + G)$
Inventory Capital ⁶	18,515	J
Initial Catalyst and Chemicals	0	K
Total Capital Investment	44,138,823	$TCI = F + G + H + I + J + K$

Operating Cost	Boiler	OAQPS Notation
<i>Direct Annual Costs</i>		
Operating and Supervisory Labor	0	L
Maintenance	662,082	$M = 0.015 \times TCI$
Reagent Consumption	315,286	N
Electricity	696,513	O
Catalyst Replacement ⁷	200,381	P
Natural Gas for Gas Reheating ⁸	210,298	Q
<i>Total Direct Annual Costs</i>	<i>2,084,560</i>	<i>$DAC = L + M + N + O + P + Q$</i>
<i>Indirect Annual Costs</i>		
Overhead, Taxes, Insurance, Administration	0	R
Capital Recovery ⁹	4,166,393	S
<i>Total Indirect Annual Costs</i>	<i>4,166,393</i>	<i>$IDAC = R + S$</i>
Total Annual Cost	6,250,953	$TAC = DAC + IDAC$
Pollutant Removed (tpy)	636	
Cost per ton of NO_x Removed	9,830	$\\$/ton = TAC / \text{Pollutant Removed}$

1. U.S. EPA OAQPS, *EPA Air Pollution Control Cost Manual (6th Edition)*, January 2002, Section 4.2, Chapter 2. Adjustments to lettering made as PEC and direct installation costs were broken out for this analysis.

2. Direct Capital Costs are based on a vendor quote for 2009 Ogelthorpe Warren Application and scaled to the P&GPP boiler size using engineering scale-up capital cost factor from Ulrich, Gael D. Chemical Engineering Process Design and Economics, 2004: $C2 = (C1 \times (S2/S1)^{0.6})$ where S1 is Ogelthorpe Boiler Capacity of 1,282 MMBtu/hr, S2 is P&GPP boiler heat input of 1,037 MMBtu/hr, C1 is Ogelthorpe's vendor quote, and C2 is the scaled cost for P&GPP.

3. Based on general OAQPS costs as presented on page 2-27 of Section 1, Chapter 2 of OAQPS Manual.

4. Estimates based on engineering knowledge and evaluation of costs for other equipment as specified in OAQPS Manual.

5. Costs were not included in OAQPS calculation or underestimated by OAQPS based on vendor data and experience.

6. Inventory capital is the cost to fill the reagent tank(s) for the first time, OAQPS Manual, Section 4.2, Chapter 2, page 2-44.

7. Catalyst replacement is calculated based on Future Worth Factor in Equations 2.51 and 2.52 of OAQPS Manual, Section 4.2, Chapter 2, page 2-47.

8. Based on fuel needed for reheating and fuel costs.

9. Capital Recovery calculated based on Equations 2.54 and 2.55 of OAQPS Manual, Section 4.2, Chapter 2, pages 2-48 and 2-49.

Table D-3. Cost Analysis Supporting Information for High-Dust, Hot-End SCR

Parameter	Units	Note(s)
Maximum Boiler Capacity	1,037 MMBtu/hr	1
Potential Inlet Emissions	0.20 lb/MMBtu	1
Controlled Outlet Emissions	0.06 lb/MMBtu	2
Removal Efficiency	70 %	2
Pollutant Removed	636 tpy	3
SCR Inlet Airflow	598,961 acfm	4,8
SCR Inlet Temperature	700 ° F	4
Volume of Catalyst	4,626 ft ³	4
Catalyst Layers	2 layers	4
Reagent Solution Consumption	46 gal/hr	4,9
Ammonia Consumption (Pure)	67 lb/hr	4,9
Water Consumption for Reagent Solution	34.18 gal/hr	4,9
Reagent Storage Capacity	16,800 gal	4
Concentration of Stored Reagent Solution	19 % Reagent	5
Pressure Drop Across the SCR and Ductwork	8.0 inches of H ₂ O	4
Electricity Usage	576 kWhr	4,8
Catalyst Life	0.91 year	4
Catalyst Cost, Initial	359.14 \$/ft ³	4
Catalyst Cost, Replacement	373.14 \$/ft ³	4
Catalyst Regeneration Cost	99.11 \$/ft ³	4
Ammonia Cost	0.53 \$/lb	4
Water Cost	0.0006 \$/gal	6
Electricity Cost	0.070 \$/kW-hr	6
SCR Equipment Life	20 years	7
Interest Rate	7.0 %	7

1. Potential inlet emissions based on maximum boiler capacity and emissions.
2. Based on vendor data. Efficiency calculated based on anticipated inlet emissions and outlet emissions.
3. Pollutant Removed (tpy) = (Uncontrolled Inlet Emissions - Controlled Outlet Emissions, lb/MMBtu) × (Maximum Boiler Capacity, MMBtu/hr) × (8,760 hr/yr) / (2000 lb/ton).
4. Value provided by Babcock Power in October 2009 PSD Permit Application for Oglethorpe Power Corporation, Warren County Biomass Energy Facility.
5. Design basis.
6. Taken from Methodology for Estimating Control Costs for Industrial, Commercial, Institutional Boilers and Process Heaters Nation Emissions Standards for Hazardous Air Pollutants -- Major Source ERG Memo April 2010.
7. Based on example problem in OAQPS Manual, Section 4.2, Chapter 2, page 2-50.
8. Scaled 2009 Oglethorpe Warren Application natural gas consumption, electricity, and water linearly by multiplying Oglethorpe's consumption rates by the ratio of P&GPP Boiler of 1,037 MMBtu/hr divided by Oglethorpe's Boiler of 1,282 MMBTU/hr.
9. Scaled 2009 Oglethorpe Warren Application reagent consumption and catalyst based on NOx emissions reduction achieved by Oglethorpe's 1282 MMBTU/hr boiler versus the proposed NOx reduction for the P&GPP boiler of 1,037 MMBtu/hr. Oglethorpe Application specified NOx reduction from 0.18 lb/MMBTU to 0.07 lb/MMBTU with heat input of 1,282 MMBTU/hr, or 141 lb/hr NOx reduction. P&GPP is assuming reduction from 0.2 lb/MMBtu to 0.06 lb/MMBtu for its 1,037 MMBtu/hr boiler which is NOx reduction of 145.18 lb/hr. Therefore the ratio of NOx reduction for P&GPP divided by NOx reduction for Oglethorpe = 1.03

Table D-4. Cost Analysis for High-Dust, Hot-End SCR

Capital Cost	Boiler	OAQPS Notation ¹
<i>Purchased Equipment Costs</i>		
Total Equipment Cost ²	9,015,373	A
Instrumentation ³	901,537	$0.10 \times A$
Sales Tax ³	270,461	$0.03 \times A$
Freight ³	450,769	$0.05 \times A$
<i>Total Purchased Equipment Costs</i>	<i>10,638,140</i>	<i>$B = 1.18 \times A$</i>
<i>Direct Installation Costs⁴</i>		
Foundations and Supports	1,063,814	$0.10 \times B$
Handling and Erection	4,255,256	$0.40 \times B$
Electrical	425,526	$0.04 \times B$
Piping	212,763	$0.02 \times B$
Insulation	106,381	$0.01 \times B$
Painting	106,381	$0.01 \times B$
Site Preparation (Site Specific)	638,288	$0.06 \times B$
<i>Total Direct Installation Costs</i>	<i>6,808,410</i>	<i>$C = 0.64 \times B$</i>
<i>Indirect Installation Costs</i>		
General Facilities ⁵	3,489,310	$0.20 \times (B + C)$
Engineering and Home Office Fees	1,744,655	$0.10 \times (B + C)$
Process Contingencies	872,328	$0.05 \times (B + C)$
Construction Management ⁵	2,616,983	$0.15 \times (B + C)$
Owner's Cost ⁵	872,328	$0.05 \times (B + C)$
<i>Total Indirect Installation Costs</i>	<i>9,595,603</i>	<i>$D = 0.55 \times (B + C)$</i>
Project Contingency ⁵	5,408,431	$E = 0.20 \times (B + C + D)$
Total Plant Cost	32,450,583	$F = B + C + D + E$
Allowance for Funds During Construction ⁵	2,271,541	$G = 0.07 \times F$
Royalty Allowance	0	H
Preproduction Costs	694,442	$I = 0.02 \times (F + G)$
Inventory Capital ⁶	12,965	J
Initial Catalyst and Chemicals	0	K
Total Capital Investment	35,429,531	$TCI = F + G + H + I + J + K$

Operating Cost	Boiler	OAQPS Notation
<i>Direct Annual Costs</i>		
Operating and Supervisory Labor	0	L
Maintenance	531,443	$M = 0.015 \times TCI$
Reagent Consumption	307,933	N
Electricity	353,220	O
Catalyst Replacement ⁷	947,918	P
Catalyst Regeneration ⁵	458,500	Q
<i>Total Direct Annual Costs</i>	<i>2,599,014</i>	<i>$DAC = L + M + N + O + P + Q$</i>
<i>Indirect Annual Costs</i>		
Overhead, Taxes, Insurance, Administration	0	R
Capital Recovery ⁸	3,344,297	S
<i>Total Indirect Annual Costs</i>	<i>3,344,297</i>	<i>$IDAC = R + S$</i>
Total Annual Cost	5,943,311	$TAC = DAC + IDAC$
Pollutant Removed (tpy)	636	
Cost per ton of NO_x Removed	9,346	$\\$/ton = TAC / \text{Pollutant Removed}$

1. U.S. EPA OAQPS, *EPA Air Pollution Control Cost Manual (6th Edition)*, January 2002, Section 4.2, Chapter 2. Adjustments to lettering made as PEC and direct installation costs were broken out for this analysis.

2. Direct Capital Costs are based on a vendor quote for 2009 Ogelthorpe Warren Application and scaled to the P&GPP boiler size using engineering scale-up capital cost factor from Ulrich, Gael D. *Chemical Engineering Process Design and Economics*, 2004: $C2 = (C1^*(S2/S1)^{0.6})$ where S1 is Ogelthorpe Boiler Capacity of 1,282 MMBtu/hr, S2 is P&GPP boiler heat input of 1,037 MMBtu/hr, C1 is Ogelthorpe's vendor quote, and C2 is the scaled cost for P&GPP.

3. Based on general OAQPS costs as presented on page 2-27 of Section 1, Chapter 2 of OAQPS Manual.

4. Estimates based on engineering knowledge and evaluation of costs for other equipment as specified in OAQPS Manual.

5. Costs were not included in OAQPS calculation or underestimated by OAQPS based on vendor data and experience.

6. Inventory capital is the cost to fill the reagent tank(s) for the first time, OAQPS Manual, Section 4.2, Chapter 2, page 2-44.

7. Catalyst replacement is calculated based on Future Worth Factor in Equations 2.51 and 2.52 of OAQPS Manual, Section 4.2, Chapter 2, page 2-47.

8. Capital Recovery calculated based on Equations 2.54 and 2.55 of OAQPS Manual, Section 4.2, Chapter 2, pages 2-48 and 2-49.

Table D-5. Cost Analysis Supporting Information for SNCR

Parameter	Boiler	Units	Note(s)
Maximum Boiler Capacity	1,037	MMBtu/hr	1
Potential Inlet Emissions	0.20	lb/MMBtu	1
Controlled Outlet Emissions	0.08	lb/MMBtu	2
Removal Efficiency	63	%	2
Pollutant Removed	568	tpy	3
Reagent Solution Consumption (Ammonia)	182.94	gal/hr	4, 9
Ammonia Consumption (Pure)	269	lb/hr	4, 9
Water Consumption for Reagent Solution	137.25	gal/hr	4, 9
Reagent Solution Storage Capacity (Ammonia)	61,500	gal	4, 9
Concentration of Injected Reagent Solution	19	% Reagent	5
Electricity Usage	40	kW-hr	4, 8
Ammonia Cost	0.53	\$/lb	4
Water Cost	0.0006	\$/gal	6
Electricity Cost	0.070	\$/kW-hr	6
SNCR Equipment Life	20	years	7
Interest Rate	7.0	%	7

1. Inlet emissions based on maximum boiler capacity and emissions.
2. Based on vendor data. Efficiency calculated based on anticipated inlet emissions and outlet emissions.
3. Pollutant Removed (tpy) = (Uncontrolled Inlet Emissions - Controlled Outlet Emissions, lb/MMBtu) × (Maximum Boiler Capacity, MMBtu/hr) × (8,760 hr/yr) / (2000 lb/ton).
4. Value provided by Babcock Power in October 2009 PSD Permit Application for Oglethorpe Power Corporation, Warren County Biomass Energy Facility.
5. Design basis.
6. Taken from Methodology for Estimating Control Costs for Industrial, Commercial, Institutional Boilers and Process Heaters Nation Emissions Standards for Hazardous Air Pollutants -- Major Source ERG Memo April 2010.
7. Based on example problem in OAQPS Manual, Section 4.2, Chapter 1, page 1-39.
8. Scaled 2009 Oglethorpe Warren Application natural gas consumption, electricity, and water linearly by multiplying Oglethorpe's consumption rates by the ratio of P&GPP Boiler of 1,037 MMBtu/hr divided by Oglethorpe's Boiler of 1,282 MMBTU/hr.
9. Scaled 2009 Oglethorpe Warren Application reagent consumption and catalyst based on NOx emissions reduction achieved by Oglethorpe's 1282 MMBTU/hr boiler versus the proposed NOx reduction for the P&GPP boiler of 1,037 MMBtu/hr. Oglethorpe Application specified NOx reduction from 0.18 lb/MMBTU to 0.11 lb/MMBTU with heat input of 1,282 MMBTU/hr, or 90 lb/hr NOx reduction. P&GPP is assuming reduction from 0.2 lb/MMBtu to 0.075 lb/MMBtu for its 1,037 MMBtu/hr boiler which is NOx reduction of 129.6 lb/hr. Therefore the ratio of NOx reduction for P&GPP divided by NOx reduction for Oglethorpe = 1.44

Table D-6. Cost Analysis for SNCR

Capital Cost	Boiler	OAQPS Notation ¹
<i>Purchased Equipment Costs</i>		
Total Equipment Cost ²	1,046,358	A
Instrumentation ³	104,636	$0.10 \times A$
Sales Tax ³	31,391	$0.03 \times A$
Freight ³	52,318	$0.05 \times A$
<i>Total Purchased Equipment Costs</i>	<i>1,234,702</i>	<i>B = 1.18 \times A</i>
<i>Direct Installation Costs⁴</i>		
Foundations and Supports	61,735	$0.05 \times B$
Handling and Erection	246,940	$0.20 \times B$
Electrical	49,388	$0.04 \times B$
Piping	24,694	$0.02 \times B$
Insulation	12,347	$0.01 \times B$
Painting	12,347	$0.01 \times B$
<i>Total Direct Installation Costs</i>	<i>407,452</i>	<i>C = 0.33 \times B</i>
<i>Indirect Installation Costs</i>		
General Facilities ⁵	164,215	$0.10 \times (B + C)$
Engineering and Home Office Fees ⁵	246,323	$0.15 \times (B + C)$
Process Contingencies	82,108	$0.05 \times (B + C)$
Construction Management ⁵	164,215	$0.10 \times (B + C)$
Owner's Cost ⁵	82,108	$0.05 \times (B + C)$
<i>Total Indirect Installation Costs</i>	<i>738,969</i>	<i>D = 0.45 \times (B + C)</i>
Project Contingency ⁵	476,225	$E = 0.20 \times (B + C + D)$
Total Plant Cost	2,857,348	$F = B + C + D + E$
Allowance for Funds During Construction	0	G
Royalty Allowance	0	H
Preproduction Costs ⁵	142,867	$I = 0.05 \times (F + G)$
Inventory Capital ⁶	47,445	J
Initial Catalyst and Chemicals ⁵	1	K
Total Capital Investment	3,047,661	TCI = F + G + H + I + J + K

Operating Cost	Boiler	OAQPS Notation
<i>Direct Annual Costs</i>		
Operating and Supervisory Labor	0	L
Maintenance	45,715	$M = 0.015 \times TCI$
Solution Consumption ⁷	1,236,325	N
Electricity	24,801	O
<i>Total Direct Annual Costs</i>	<i>1,306,840</i>	<i>DAC = L + M + N + O</i>
<i>Indirect Annual Costs</i>		
Overhead, Taxes, Insurance, Administration ⁵	0	P
Capital Recovery ⁸	287,678	Q
<i>Total Indirect Annual Costs</i>	<i>287,678</i>	<i>IDAC = P + Q</i>
Total Annual Cost	1,594,518	TAC = DAC + IDAC
Pollutant Removed (tpy)	568	
Cost per ton of NO_x Removed	2,808	$\$/ton = TAC / Pollutant\ Removed$

1. U.S. EPA OAQPS, *EPA Air Pollution Control Cost Manual (6th Edition)*, January 2002, Section 4.2, Chapter 1. Adjustments to lettering made as PEC and direct installation costs were broken out for this analysis.

2. Direct Capital Costs are based on a vendor quote for 2009 Ogelthorpe Warren Application and scaled to the P&GPP boiler size using engineering scale-up capital cost factor from Ulrich, Gael D. *Chemical Engineering Process Design and Economics*, 2004: $C2 = (C1 \times (S2/S1)^{0.6})$ where S1 is Ogelthorpe Boiler Capacity of 1,282 MMBtu/hr, S2 is P&GPP boiler heat input of 1,037 MMBtu/hr, C1 is Ogelthorpe's vendor quote, and C2 is the scaled cost for P&GPP.

3. Based on general OAQPS costs as presented on page 2-27 of Section 1, Chapter 2 of OAQPS Manual.

4. Estimates based on engineering knowledge and evaluation of costs for other equipment as specified in OAQPS Manual.

5. Costs were not included in OAQPS calculation or underestimated by OAQPS based on vendor data and experience.

6. Inventory capital is the cost to fill the reagent tank(s) for the first time, OAQPS Manual, Section 4.2, Chapter 1, page 1-32.

7. Based on ammonia and water consumption.

8. Capital Recovery calculated based on Equations 1.33 and 1.34 of OAQPS Manual, Section 4.2, Chapter 1, pages 1-37 and 1-38.

Table D-7. Cost Analysis Supporting Information for Wet Flue Gas Desulfurization (WFGD)

Parameter	Boiler	Units	Note(s)
Maximum Boiler Capacity	1,037	MMBtu/hr	1
Potential Inlet Emissions	0.260	lb/MMBtu	1
Controlled Outlet Emissions	0.013	lb/MMBtu	2
Removal Efficiency	95	%	2
Pollutant Removed	1,122	tpy	3
Solvent Consumption	6,309	gal/hr	4,8
Scrubber Inlet Temperature	335	° F	4
Scrubber Inlet Airflow	408,600	acfm	2
Pressure Drop Across Scrubber	12.00	inches of H ₂ O	4
Total Electricity Usage	1,618	kW-hr	4,8
Caustic Consumption	0.28	ton/hr	5,9
Caustic Consumption	1.8	ton/ton SO ₂ removed	5,9
Solid Waste Generated	2.8	ton/ton SO ₂ removed	5
Solvent Usage Cost (Water)	0.0006	\$/gal	6
Operating Labor Cost	51.26	\$/hr	6
Maintenance Labor Cost	51.26	\$/hr	6
Electricity Cost	0.070	\$/kW-hr	6
Caustic Cost	600.00	\$/ton	6
Solid Waste Disposal Cost	6.00	\$/ton	6
Scrubber Equipment Life	15	years	7
Interest Rate	7.0	%	7

1. Inlet emissions based on maximum boiler capacity and emissions.
2. Based on vendor data. Efficiency calculated based on anticipated inlet emissions and outlet emissions.
3. Pollutant Removed (tpy) = (Uncontrolled Inlet Emissions - Controlled Outlet Emissions, lb/MMBtu) × (Maximum Boiler Capacity, MMBtu/hr) × (8,760 hr/yr) / (2000 lb/ton).
4. Value provided by Babcock Power in October 2009 PSD Permit Application for Oglethorpe Power Corporation, Warren County Biomass Energy Facility.
5. Based on design pollutant loading and limestone usage rate.
6. Taken from Methodology for Estimating Control Costs for Industrial, Commercial, Institutional Boilers and Process Heaters Nation Emissions Standards for Hazardous Air Pollutants -- Major Source ERG Memo April 2010.
7. Per OAQPS Manual, Section 5.2, Chapter 1, page 1-30.
8. Scaled 2009 Oglethorpe Warren Application natural gas consumption, electricity, and water linearly by multiplying Oglethorpe's consumption rates by the ratio of P&GPP Boiler of 1,037 MMBtu/hr divided by Oglethorpe's Boiler of 1,282 MMBTU/hr.
9. Scaled 2009 Oglethorpe Warren Application reagent consumption and catalyst based on SO₂ emissions reduction achieved by Oglethorpe's 1282 MMBTU/hr boiler versus the proposed SO₂ reduction for the P&GPP boiler of 1,037 MMBtu/hr. Oglethorpe Application specified SO₂ reduction from 0.066lb/MMBTU to 0.005 lb/MMBTU with heat input of 1,282 MMBTU/hr, or 78 lb/hr SO₂ reduction. P&GPP is assuming reduction from 0.26 lb/MMBtu to 0.013 lb/MMBtu for its 1,037 MMBtu/hr boiler which is SO₂ reduction of 256 lb/hr. Therefore the ratio of SO₂ reduction for P&GPP divided by SO₂ reduction for Oglethorpe = 3.28

Table D-8. Cost Analysis for Wet Flue Gas Desulfurization (WFGD)

Capital Cost	Boiler	OAQPS Notation ¹
<i>Purchased Equipment Costs</i>		
Total Equipment Cost ²	22,576,999	A
Instrumentation ³	2,257,700	$0.10 \times A$
Sales Tax ³	677,310	$0.03 \times A$
Freight ³	1,128,850	$0.05 \times A$
<i>Total Purchased Equipment Costs</i>	<i>26,640,859</i>	<i>$B = 1.18 \times A$</i>
<i>Direct Installation Costs</i>		
Foundations and Supports	3,196,903	$0.12 \times B$
Handling and Erection	10,656,344	$0.40 \times B$
Electrical	266,409	$0.01 \times B$
Piping	7,992,258	$0.30 \times B$
Insulation	266,409	$0.01 \times B$
Painting	266,409	$0.01 \times B$
Site Preparation (Site-Specific)	799,226	$0.03 \times B$
Building (Site-Specific)	1,332,043	$0.05 \times B$
<i>Total Direct Installation Costs</i>	<i>24,775,999</i>	<i>$C = 0.93 \times B$</i>
<i>Indirect Installation Costs</i>		
Engineering	2,664,086	$0.10 \times B$
Construction and Field Expense	2,664,086	$0.10 \times B$
Contractor Fees	2,664,086	$0.10 \times B$
Start-up ³	532,817	$0.02 \times B$
Performance Test ³	53,282	$0.002 \times B$
Process Contingencies	799,226	$0.03 \times B$
Owners Cost ³	1,332,043	$0.05 \times B$
<i>Total Indirect Installation Costs</i>	<i>10,709,625</i>	<i>$D = 0.402 \times B$</i>
Project Contingency ³	12,425,297	$E = 0.20 \times (B + C + D)$
Total Plant Cost	74,551,779	$F = B + C + D + E$
Allowance for Funds During Construction ³	5,218,625	$G = 0.07 \times F$
Inventory Capital ^{3,4}	57,095	H
Total Capital Investment	79,827,499	TCI = (F + G + H)

Operating Cost	Boiler	OAQPS Notation
<i>Direct Annual Costs</i>		
Operating Labor (1/2 hr, per 8-hr shift)	28,065	I
Supervisory Labor	4,210	$J = 0.15 \times I$
Maintenance Labor (1/2 hr, per 8-hr shift)	28,065	K
Maintenance Materials	28,065	$L = K$
Scrubbant ⁵	33,162	M
Chemicals (Caustic)	1,225,103	N
Solid Waste Disposal	18,578	O
Electricity	992,026	P
<i>Total Direct Annual Costs</i>	<i>2,357,273</i>	<i>$DAC = I + J + K + L + M + N + O + P$</i>
<i>Indirect Annual Costs</i>		
Overhead	53,043	$Q = 0.60 \times (I + J + K + L)$
Administrative Charges	1,596,550	$R = 0.02 \times TCI$
Property Tax	798,275	$S = 0.01 \times TCI$
Insurance	798,275	$T = 0.01 \times TCI$
Capital Recovery ⁶	8,764,630	U
<i>Total Indirect Annual Costs</i>	<i>12,010,773</i>	<i>$IDAC = Q + R + S + T + U$</i>
Total Annual Cost	14,368,046	$TAC = DAC + IDAC$
Pollutant/Additional Pollutant Removed (tpy)	1,122	
Cost per ton of SO₂ Removed	12,807	$\\$/ton = TAC / \text{Pollutant Removed}$

1. U.S. EPA OAQPS, *EPA Air Pollution Control Cost Manual (6th Edition)*, January 2002, Section 5.2, Chapter 1. Values based on average requirements specified in OAQPS Manual, Section 5.2, Chapter 1, pages 1-27 and 1-28 unless otherwise noted. Adjustments to lettering made as PEC and direct installation costs were broken out for this analysis.

2. Direct Capital Costs are based on a vendor quote for 2009 Ogelthorpe Warren Application and scaled to the P&GPP boiler size using engineering scale-up capital cost factor from Ulrich, Gael D. *Chemical Engineering Process Design and Economics*, 2004: $C2 = (C1 \times (S2/S1)^{0.6})$ where S1 is Ogelthorpe Boiler Capacity of 1,282 MMBtu/hr, S2 is P&GPP boiler heat input of 1,037 MMBtu/hr, C1 is Ogelthorpe's vendor quote, and C2 is the scaled cost for P&GPP.

3. Costs were not included in OAQPS calculation or underestimated by OAQPS based on vendor data and experience.

4. Inventory capital is the cost to store limestone for 14 days.

5. Cost is conservatively based on usage of water as a solvent.

6. Capital Recovery calculated based on Equations 1.33 and 1.34 of OAQPS Manual, Section 4.2, Chapter 1, pages 1-37 and 1-38.

Table D-9. Cost Analysis Supporting Information for Duct Sorbent Injection

Parameter	Boiler, SO ₂	Units	Note(s)
Maximum Boiler Capacity	1,037	MMBtu/hr	1
Potential Inlet Emissions	0.260	lb/MMBtu	1
Controlled Outlet Emissions	0.020	lb/MMBtu	2
Removal Efficiency	92	%	2
Pollutant Removed	1,090	tpy	3
Total Electricity Usage	252	kW-hr	4,8
Trona Consumption	1.43	ton/hr	5,9
Trona Consumption	11.5	ton/ton pollutant removed	5,9
Solid Waste Generated	12.5	ton/ton pollutant removed	5,9
Water Usage Cost	0.0006	\$/gal	6
Operating Labor Cost	51.26	\$/hr	6
Maintenance Labor Cost	51.26	\$/hr	6
Electricity Cost	0.070	\$/kW-hr	6
Trona Cost	150.00	\$/ton reagent	6
Solid Waste Disposal Cost	6.00	\$/ton material	6
Equipment Life	15	years	7
Interest Rate	7.0	%	7

1. Inlet emissions based on maximum boiler capacity and emissions.
2. Based on vendor data. Efficiency calculated based on anticipated inlet emissions and outlet emissions.
3. Pollutant Removed (tpy) = (Uncontrolled Inlet Emissions - Controlled Outlet Emissions, lb/MMBtu) × (Maximum Boiler Capacity, MMBtu/hr) × (8,760 hr/yr) / (2000 lb/ton).
4. Value provided by Babcock Power in October 2009 PSD Permit Application for Oglethorpe Power Corporation, Warren County Biomass Energy Facility.
5. Based on design pollutant loading and trona usage rate.
6. Taken from Methodology for Estimating Control Costs for Industrial, Commercial, Institutional Boilers and
7. Per OAQPS Manual, Section 5.2, Chapter 1, page 1-30.
8. Scaled 2009 Oglethorpe Warren Application natural gas consumption, electricity, and water linearly by multiplying Oglethorpe's consumption rates by the ratio of P&GPP Boiler of 1,037 MMBtu/hr divided by Oglethorpe's Boiler of 1,282 MMBTU/hr.
9. Scaled 2009 Oglethorpe Warren Application reagent consumption and catalyst based on SO₂ emissions reduction achieved by Oglethorpe's 1282 MMBTU/hr boiler versus the proposed SO₂ reduction for the P&GPP boiler of 1,037 MMBtu/hr. Oglethorpe Application specified SO₂ reduction from 0.066 lb/MMBTU to 0.01 lb/MMBTU with heat input of 1,282 MMBTU/hr, or 71 lb/hr SO₂ reduction. P&GPP is assuming reduction from 0.26 lb/MMBtu to 0.02 lb/MMBtu for its 1,037 MMBtu/hr boiler which is SO₂ reduction of 248 lb/hr. Therefore the ratio of SO₂ reduction for P&GPP divided by SO₂ reduction for Oglethorpe = 3.5

Table D-10. Cost Analysis for Duct Sorbent Injection

Capital Cost	Boiler, SO ₂	OAQPS Notation
<i>Purchased Equipment Costs¹</i>		
Total Equipment Cost ²	1,964,595	A
Instrumentation	196,460	$0.10 \times A$
Sales Tax	58,938	$0.03 \times A$
Freight	98,230	$0.05 \times A$
<i>Total Purchased Equipment Costs</i>	<i>2,318,223</i>	<i>B = 1.18 \times A</i>
<i>Direct Installation Costs³</i>		
Foundations and Supports	231,822	$0.10 \times B$
Handling and Erection	927,289	$0.40 \times B$
Electrical	92,729	$0.04 \times B$
Piping	115,911	$0.05 \times B$
Insulation	23,182	$0.01 \times B$
Painting	23,182	$0.01 \times B$
<i>Total Direct Installation Costs</i>	<i>1,414,116</i>	<i>C = 0.61 \times B</i>
<i>Indirect Installation Costs⁴</i>		
Engineering ⁵	347,733	$0.15 \times B$
Construction and Field Expense	231,822	$0.10 \times B$
Contractor Fees	231,822	$0.10 \times B$
Start-up ³	231,822	$0.10 \times B$
Performance Test	23,182	$0.01 \times B$
Process Contingencies	69,547	$0.03 \times B$
Owners Cost ³	115,911	$0.05 \times B$
<i>Total Indirect Installation Costs</i>	<i>1,251,840</i>	<i>D = 0.54 \times B</i>
Project Contingency ⁵	996,836	$E = 0.20 \times (B + C + D)$
Total Plant Cost	5,981,014	$F = B + C + D + E$
Inventory Capital ^{5,6}	72,045	G
Total Capital Investment	6,053,059	TCI = (F + G)

Operating Cost	Boiler, SO ₂	OAQPS Notation
<i>Direct Annual Costs</i>		
Operating Labor (0 hr, per 8-hr shift)	0	H
Supervisory Labor	0	$I = 0.15 \times H$
Maintenance Labor (0.5 hr, per 8-hr shift) ⁴	28,065	J
Maintenance Materials ⁴	28,065	$K = J$
Reagent	1,878,308	L
Solid Waste Disposal	81,673	M
Electricity	154,756	N
<i>Total Direct Annual Costs</i>	<i>2,170,867</i>	<i>DAC = H + I + J + K + L + M + N</i>
<i>Indirect Annual Costs⁴</i>		
Overhead	33,678	$L = 0.60 \times (H + I + J + K)$
Administrative Charges	121,061	$M = 0.02 \times TCI$
Property Tax	60,531	$N = 0.01 \times TCI$
Insurance	60,531	$O = 0.01 \times TCI$
Capital Recovery ⁷	664,593	P
<i>Total Indirect Annual Costs</i>	<i>940,394</i>	<i>IDAC = L + M + N + O + P</i>
Total Annual Cost	3,111,260	TAC = DAC + IDAC
Pollutant Removed (tpy)	1,090	
Cost per ton of SO₂ Removed	2,854	<i>\$/ton = TAC / Pollutant Removed</i>

1. U.S. EPA OAQPS, *EPA Air Pollution Control Cost Manual (6th Edition)*, January 2002, Section 1, Chapter 2. Values based on average requirements specified on page 2-27 unless otherwise noted. Adjustments to lettering made as PEC and direct installation costs were broken out for this analysis.
2. Direct Capital Costs are based on a vendor quote for 2009 Ogelthorpe Warren Application and scaled to the P&GPP boiler size using engineering scale-up capital cost factor from Ulrich, Gael D. Chemical Engineering Process Design and Economics, 2004: $C2 = (C1 \times (S2/S1)^{0.6})$ where S1 is Ogelthorpe Boiler Capacity of 1,282 MMBtu/hr, S2 is P&GPP boiler heat input of 1,037 MMBtu/hr, C1 is Ogelthorpe's vendor quote, and C2 is the scaled cost for P&GPP.
3. Estimates based on engineering knowledge and evaluation of costs for other equipment as specified in OAQPS Manual.
4. Assumed the values listed in OAQPS Manual, Section 5.2, Chapter 1, are appropriate unless otherwise noted.
5. Costs were not included in OAQPS calculation or underestimated by OAQPS based on vendor data and experience.
6. Inventory capital is the cost to store reagent for 14 days.

Table D-11. Cost Analysis Supporting Information for Tail-End Oxidation Catalyst

Parameter	Boiler - CO	Boiler - VOC	Units	Note(s)
Maximum Boiler Capacity	1,037	1,037	MMBtu/hr	1
Uncontrolled Inlet Emissions	0.10	0.007	lb/MMBtu	1
Controlled Outlet Emissions	0.02	0.002	lb/MMBtu	2
Removal Efficiency	70	70	%	2
Pollutant Removed	386	22	tpy	3
Inlet Airflow	496,660	496,660	acfm	4,9
Inlet Temperature	425	525	° F	4
Volume of Catalyst	800	800	ft ³	4
Pressure Drop Across the Oxidation Catalyst	10.0	10.5	inches of H ₂ O	4
Electricity Usage	720.0	720.0	kW-hr	4,9
Catalyst Life	3	3	year	4
Natural Gas Consumption for Gas Reheating	34,859	34,859	ft ³ /hr	5
Catalyst Cost, Initial	387.50	387.50	\$/ft ³	4
Catalyst Cost, Replacement	401.50	401.50	\$/ft ³	4
Operating Labor Cost	51.26	51.26	\$/hr	6
Maintenance Labor Cost	51.26	51.26	\$/hr	6
Electricity Cost	0.070	0.07	\$/kW-hr	6
Natural Gas Cost	6.88	6.88	\$/1000 ft ³	6
Oxidation Catalyst Equipment Life	10	10	years	8
Interest Rate	7.0	7.0	%	8

1. Potential inlet emissions based on maximum boiler capacity and emissions.

2. Based on vendor data. Efficiency calculated based on anticipated inlet emissions and outlet emissions.
(8,760 hr/yr) / (2000 lb/ton).

4. Value provided by Babcock Power in October 2009 PSD Permit Application for Oglethorpe Power Corporation, Warren County Biomass Energy Facility.

5. Calculated based on reheating needed (MMBtu/hr) and natural gas heat input capacity.

6. Taken from Methodology for Estimating Control Costs for Industrial, Commercial, Institutional Boilers and Process Heaters
Nation Emissions Standards for Hazardous Air Pollutants -- Major Source ERG Memo April 2010.

7. Engineering estimate.

8. Based on example problem in OAQPS Manual, Section 3.2, Chapter 2, page 2-45.

9. Scaled 2009 Oglethorpe Warren Application natural gas consumption, electricity, and water linearly by multiplying Oglethorpe's consumption rates by the ratio of P&GPP Boiler of 1,037 MMBtu/hr divided by Oglethorpe's Boiler of 1,282 MMBTU/hr.

Table D-12. Cost Analysis for Tail-End Oxidation Catalyst (Stand-Alone)

Capital Cost	CO	VOC	OAQPS Notation ¹
<i>Purchased Equipment Costs</i>			
Total Equipment Cost ²	6,295,614	6,295,614	A
Instrumentation	629,561	629,561	$0.10 \times A$
Sales Tax	188,868	188,868	$0.03 \times A$
Freight	314,781	314,781	$0.05 \times A$
<i>Total Purchased Equipment Costs</i>	<i>7,428,825</i>	<i>7,428,825</i>	<i>B = 1.18 \times A</i>
<i>Direct Installation Costs</i>			
Foundations and Supports	594,306	594,306	$0.08 \times B$
Handling and Erection	1,040,035	1,040,035	$0.14 \times B$
Electrical	297,153	297,153	$0.04 \times B$
Piping	148,576	148,576	$0.02 \times B$
Insulation	74,288	74,288	$0.01 \times B$
Painting	74,288	74,288	$0.01 \times B$
<i>Total Direct Installation Costs</i>	<i>2,228,647</i>	<i>2,228,647</i>	<i>C = 0.30 \times B</i>
<i>Indirect Installation Costs</i>			
Engineering	742,882	742,882	$0.10 \times B$
Construction and Field Expense	371,441	371,441	$0.05 \times B$
Contractor Fees	742,882	742,882	$0.10 \times B$
Start-up	148,576	148,576	$0.02 \times B$
Performance Test	74,288	74,288	$0.01 \times B$
Process Contingencies	222,865	222,865	$0.03 \times B$
Owners Cost ³	371,441	371,441	$0.05 \times B$
<i>Total Indirect Installation Costs</i>	<i>2,674,377</i>	<i>2,674,377</i>	<i>D = 0.36 \times B</i>
Project Contingency ³	2,466,370	2,466,370	$E = 0.20 \times (B + C + D)$
Total Plant Cost	14,798,219	14,798,219	$F = B + C + D + E$
Allowance for Funds During Construction ³	1,035,875	1,035,875	$G = 0.07 \times F$
Total Capital Investment	15,834,094	15,834,094	TCI = (F + G)

Operating Cost	CO	VOC	OAQPS Notation
<i>Direct Annual Costs</i>			
Operating Labor (0.5 hr, per 8-hr shift)	28,065	28,065	H
Supervisory Labor	4,210	4,210	$I = 0.15 \times H$
Maintenance Labor (0.5 hr, per 8-hr shift)	28,065	28,065	J
Maintenance Materials	28,065	28,065	$K = J$
Electricity	441,525	441,525	L
Catalyst Replacement ⁴	99,910	99,910	M
Natural Gas Reheating	2,100,906	2,100,906	N
<i>Total Direct Annual Costs</i>	<i>2,730,745</i>	<i>2,730,745</i>	<i>DAC = H + I + J + K + L + M + N</i>
<i>Indirect Annual Costs</i>			
Overhead	53,043	53,043	$O = 0.60 \times (H + I + J + K)$
Administrative Charges	316,682	316,682	$P = 0.02 \times TCI$
Property Tax	158,341	158,341	$Q = 0.01 \times TCI$
Insurance	158,341	158,341	$R = 0.01 \times TCI$
Capital Recovery ⁵	2,254,419	2,254,419	S
<i>Total Indirect Annual Costs</i>	<i>2,940,825</i>	<i>2,940,825</i>	<i>IDAC = O + P + Q + R + S</i>
Total Annual Cost	4,985,164	4,985,164	TAC = DAC + IDAC
Pollutant Removed (tpy)	386	22	
Cost per ton of Pollutant Removed	12,912	223,991	$\\$/ton = TAC / Pollutant Removed$

1. U.S. EPA OAQPS, *EPA Air Pollution Control Cost Manual (6th Edition)*, January 2002, Section 3.2, Chapter 2.

2. Direct Capital Costs are based on a vendor quote for 2009 Ogelthorpe Warren Application and scaled to the P&GPP boiler size using engineering scale-up capital cost factor from Ulrich, Gael D. Chemical Engineering Process Design and Economics, 2004: $C2 = (C1^*(S2/S1)^{0.6})$ where S1 is Ogelthorpe Boiler Capacity of 1,282 MMBtu/hr, S2 is P&GPP boiler heat input of 1,037 MMBtu/hr, C1 is Ogelthorpe's vendor quote, and C2 is the scaled cost for P&GPP.

3. Costs were not included in OAQPS calculation or underestimated by OAQPS based on vendor data and experience.

4. Catalyst replacement is calculated based Future Worth Factor from Equations 2.51 and 2.52 of OAQPS Manual, Section 4.2, Chapter 2, page 2-47.

5. Capital Recovery calculated based on Equations 2.54 and 2.55 of OAQPS Manual, Section 4.2, Chapter 2, pages 2-48 and 2-49.