Prevention of Significant Air Quality Deterioration Review
Of Procter & Gamble Paper Products Company - Albany
Located in Dougherty County, Georgia

PRELIMINARY DETERMINATION
SIP Permit Application No. 17242
August 2007

State of Georgia
Department of Natural Resources
Environmental Protection Division
Air Protection Branch

Stationary Source Permitting Program (SSPP)
Prepared by
Furqan Shaikh – Chemicals Unit
Modeling Approved by: **Peter Courtney** **Data and Modeling Unit**
Reviewed and Approved by:
David Matos – Chemicals Unit Coordinator **Jac Capp – SSPP Manager**
Heather Abrams – Chief, Air Protection Branch

SUMMARY

The Environmental Protection Division (EPD) has reviewed the application submitted by Procter & Gamble Paper Products Company for a permit to modify Waste Fuel Boiler No. 2 (Source Code: B002) at the Albany, Georgia Plant. This boiler is permitted to burn fuel oil and biomass (wood waste, peanut hull, peacan hull, fines and plastic). The proposed project will allow Boiler B002 to operate at its full rated capacity on a consistent basis. Boiler B002, installed in 1981, has been experiencing reliability and capacity derating problems in the recent years due to aging. The objective of the proposed Boiler B002 upgrade project is to conduct the repair and maintenance activities necessary to allow the operation of the boiler at its full rated capacity on a consistent basis.

The modification of the Procter & Gamble Paper Products Company due to this project will result in an emissions increase in carbon monoxide (CO), lead (Pb), nitrogen oxides (NO_X), particulate matter, (PM), particulate matter less than 10 micrometers (PM_{10}), particulate matter less than 2.5 micrometers ($PM_{2.5}$), sulfur dioxide (SO_2), and volatile organic compounds (VOC). A Prevention of Significant Deterioration (PSD) analysis was performed for the facility for all pollutants to determine if any increase was above the "significance" level. The NO_X emissions increase was above the PSD significant level threshold. For pollutants carbon monoxide, particulate matter, sulfur dioxide, and volatile organic compounds, the facility has elected to voluntary take PSD avoidance limits on Boiler B002 to ensure the emissions increase is below the respective PSD significant threshold. These limits are included in Conditions 3.17, 3.18 and 3.19 of this permit amendment.

The Procter & Gamble Paper Products Company is located in Dougherty County, which is classified as "attainment" or "unclassifiable" for SO_2, $PM_{2.5}$ and PM_{10}, NO_X, CO, and ozone (VOC) in accordance with Section 107 of the Clean Air Act, as amended August 1977.

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

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

It has been determined through approved modeling techniques that the estimated emissions will not cause or contribute to a violation of any ambient air standard or allowable PSD increment in the area surrounding the facility or in Class I areas located within 200 km of the facility. It has further been determined that the proposal will not cause impairment of visibility or detrimental effects on soils or vegetation. Any air quality impacts produced by project-related growth should be inconsequential.

This Preliminary Determination concludes that an Air Quality Permit should be issued to Procter & Gamble Paper Products Company for the modifications necessary to to conduct the Boiler No. 2 repar and maintenance activities. Various conditions have been incorporated into the current Title V operating permit to ensure and confirm compliance with all applicable air quality regulations. A copy of the draft permit amendment is included in Appendix A.

1.0 INTRODUCTION

On February 1, 2007, Procter & Gamble Paper Products Company (hereafter P&G) submitted an application for an air quality permit to modify Waste Fuel Boiler No. 2 (Source Code: B002). The facility is located at 512 Liberty Expressway Southeast in Albany, Dougherty County.

Based on the proposed project description and data provided in the permit application, the estimated incremental increases of regulated pollutants from the facility are listed in Table 1 below:

Table 1-1: Emissions Increases from the Project

Pollutant	Baseline Years	Potential Emissions Increase (tpy)	PSD Significant Emission Rate (tpy)	Subject to PSD Review
PM	2003-2004	19	25	No
PM_{10}	2003-2004	14	15	No
VOC	2003-2004	5	40	No
NO_X	2003-2004	155	40	Yes
CO	2003-2004	89	100	No
SO_2	2003-2004	39	40	No
TRS	2003-2004	N/A	10	No
Pb	2003-2004	0.014	0.6	No
Fluorides	2003-2004	N/A	3	No
H_2S	2003-2004	N/A	10	No
SAM	2003-2004	N/A	7	No

The definition of baseline actual emissions is the average emission rate, in tons per year, at which the emission unit actually emitted the pollutant during any consecutive 24-month period selected by the facility within the 10-year period immediately proceeding the date a complete permit application was received by EPD. The net increases were calculated by subtracting the past actual emissions (based upon the annual average emissions from 24-month time period) from the future actual emissions of the modified equipment and associated emission increases from non-modified equipment. The facility has elected to voluntary take PSD avoidance limits for carbon monoxide, particulate matter, sulfur dioxide, and volatile organic compounds on Boiler B002 to ensure the emissions increase is below the respective PSD significant threshold. These limits are included in Conditions 3.17, 3.18 and 3.19 of this permit amendment. Table 1-2 details this emissions summary. The emissions calculations for Tables 1-1 and 1-2 can be found in detail in the facility's PSD application (see Section 3, PSD Review Documentation of Application No. 17242). These calculations have been reviewed and approved by the Division. Georgia EPD is following EPA's guidance in using PM_{10} as a surrogate for $PM_{2.5}$ until final $PM_{2.5}$ NSR implementation rules are adopted.

Table 1-2: Net Change in Emissions Due to the Major PSD Modification

Pollutant	Increase from Boiler B002		Associated Units Increase (tpy)	Total Increase (tpy)
	Past Actual	Future Actual		
PM/PM_{10}	13.99/8.83	33.17/22.51	N/A	19/14
VOC	11.15	16.49	N/A	5
NO_X	109.63	264.90	N/A	155
CO	384.45	473.04	N/A	89
SO_2	43.14	81.69	N/A	39
TRS	N/A	N/A	N/A	N/A
Pb	0.03	0.05	N/A	0.02
Fluorides	N/A	N/A	N/A	N/A
H_2S	N/A	N/A	N/A	N/A
SAM	N/A	N/A	N/A	N/A

Based on the information presented in Tables 1-1 and 1-2 above, P&G's proposed modification, as specified per Georgia Air Quality Application No. 17242, is classified as a major modification under PSD because the potential emissions of NO_X exceed the PSD significant rate of 40 tons per year.

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

2.0 PROCESS DESCRIPTION

According to Application No. 17242, P&G has proposed to conduct major repair and maintenance of the waste fuel boiler at the Albany, Georgia Plant. Boiler 2 (Source Code: B002) is a Foster Wheeler SFX unit, Model Number MF #600-1-NB220. The boiler was installed in 1981 with a rated capacity of 216 MMBtu/hr and 150,000 lb/hr of steam. The unit is currently permitted for firing of biomass (e.g., bark, wood waste, peanut and pecan hulls), No. 2 fuel oil, paper fines, and plastic. Boiler B002 is equipped with a Wet Electrostatic Precipitator (WEP) to control PM emissions.

Boiler B002 has been experiencing capacity derating problems in the recent years due to aging and is in need of major repairs. Currently, continuous operation of the boiler at its full rated steam capacity of 150,000 lb/hr cannot be maintained for an extended period of time. Attempts to operate the boiler at or near the rated load for an extended period of time result in unstable and unsafe operation. Although Boiler 2 can operate at its full capacity for a short period of time, the current operating load for the boiler has been limited to approximately 130,000 lb/hr of steam for extended time periods.

The scope of the Boiler B002 upgrade project consists of a major upgrade of the following systems:

- Overfire air (OFA) system
- Controls and instrumentation
- Induced draft (ID) fan
- Bottom ash handing system
- Fuel delivery system

Overfire Air (OFA) System

The biomass boiler technology was in the early stages of development around the time when Boiler B002 was installed. At that time, the biomass combustion furnace design was mainly borrowed from the coal combustion technology in use at that time and did not take into account the differences in combustion characteristics of biomass and coal. Through the years it has been learned that biomass fuels require a greater proportion of OFA because of their higher volatile content. The Boiler B002 OFA system is currently designed to provide approximately 20 percent of combustion air, whereas the current biomass boiler technology recommends OFA in the range of 50 to 70 percent. The OFA system improvement will result in more efficient combustion of biomass and also improve the operational reliability of the boiler for extended time periods.

Upgrade Controls

The objective of the controls upgrade scope is to allow the operator a fully automatic, “single knob” control of the boiler. Currently, the panel operator changes several variables to make an adjustment in steam production. The proposed control upgrade will greatly reduce dependency on operator expertise, variation from shift to shift, steam disruptions due to operator inexperience, and the delayed responses inherent in the combustion process. The proposed control system improvements will upgrade the boiler’s instrumentation and controls to the current state of the technology.

ID Fan Improvements

The Boiler B002 ID fan is currently designed for a wet scrubber system that was replaced by the WEP in 1989. The pressure drop design basis for the wet scrubber was 40 inches of water, as compared to 18 inches of water for the WEP. Because the fan is oversized for the Boiler B002 WEP system, operating the boiler at loads below 33 percent requires the ID fan to be operated manually in the range below its preferred turndown ratio limit. Inability to properly control the fan pressure drop at low loads significantly impacts the boiler operation. The upgrade scope of the ID fan will include an installation of a new Variable Frequency Drive (VFD) or magnetic adjustable speed drive (ASD) to allow reliable operation of the ID fan at all firing rates.

Bottom Ash Handling System Upgrades

The OFA and control system improvements will change the thickness of the ash bed coming off the grate. Currently, due to the high percentage of combustion air that comes under the grate, all of the fine ash is carried up through the generating bank and drops out in the air heater or travels to the WEP. The bottom ash coming off the grate is heavy sand particles, rocks and clinkers, and some large pieces of unburned wood. This bottom ash currently drops into a low wall, open-top, dumpster.

With the new control strategy and improved OFA system, the undergrate air will be reduced by 33 to 50 percent. The ash bed coming off the grate upon OFA system improvement is expected to be much thicker and have a much smaller particle size distribution. To prevent fugitive dust emissions, the open dumpster operation will be converted to a closed dumpster system and a new conveying system to transport the ash from the ash chute to the dumpster will be installed.

Fuel Delivery System Upgrade

The Boiler B002 project scope includes upgrade to the biomass fuel delivery system that will replace the existing single hydraulic pump with four smaller hydraulic pumps and associated supply piping. The installation of four pumps with supply piping will result in increased reliability because of elimination of a single point of failure.

The facility also plans to install an economizer unit as part of this boiler upgrade project. This economizer unit will enhance the thermal efficiency of Boiler B002 by recovering heat energy from the flue gas stream.

The P&G permit application and supporting documentation are included in Appendix A of this Preliminary Determination and can be found online at www.georgiaair.org/airpermit.

3.0 REVIEW OF APPLICABLE RULES AND REGULATIONS

State Rules

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

Georgia Rule 391-3-1-.02(2)(d) limits particulate emission from fuel burning equipment. Particulate emissions limit for the waste fuel boiler upon completion of the proposed repair and maintenance activities is 0.03 pounds per million BTU per the PSD avoidance limit. Visible emissions from the boiler are limited per Georgia Rule 391-3-1-.02(2)(3) to twenty (20) percent except for one six minute period per hour of not more than twenty-seven (27) percent opacity.

Georgia Rule 391-3-1-.02(2)(g)2 limits the fuel sulfur content of the fuels consumed in the boiler to not equal or exceed 2.5 weight percent. P&G proposes to burn biomass fuels in the boiler that have an emission factor of 0.025 pounds per million BTU heat input. The sulfur content of No. 2 fuel oil will be limited to 0.34 percent. With these facts in mind, the PSD avoidance limits subsume the applicable state emission limits.

Federal Rule - PSD

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

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

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

Definition of BACT

The PSD regulation requires that BACT be applied to all regulated air pollutants emitted in significant amounts. Section 169 of the Clean Air Act defines BACT as an emission limitation reflecting the maximum degree of reduction that the permitting authority (in this case, EPD), on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such a facility through application of production processes and available methods, systems, and techniques. In all cases BACT must establish emission limitations or specific design characteristics at least as stringent as applicable New Source Performance Standards (NSPS). In addition, if EPD determines that there is no economically reasonable or technologically feasible way to measure the emissions, and hence to impose and enforceable emissions standard, it may require the source to use a design, equipment, work practice or operations standard or combination thereof, to reduce emissions of the pollutant to the maximum extent practicable.

The BACT determination should, at a minimum, meet two core requirements.[1] The first core requirement is that the determination follow a "top-down" selection approach. The second core requirement is that the selection of a particular control system as BACT must be justified in terms of the statutory criteria and supported by the record and must explain the basis for the rejection of other more stringent candidate control systems.

EPD's procedures for performing a top down BACT analysis are set forth in EPA's Draft New Source Review Workshop Manual (Manual), dated October 1990. One critical step in the BACT analysis is to determine if a control option is technically feasible.[2] If a control is determined to be infeasible, it is eliminated from further consideration. The Manual applies several criteria for determining technical feasibility. The first is straightforward: if the control has been installed and operated by the type of source under review, it is demonstrated and technically feasible.

For controls not demonstrated using this straightforward approach, the Manual applies a more complex approach that involves two concepts for determining technical feasibility: availability and applicability. A technology is considered available if it can be obtained through commercial channels. An available control is applicable if it can be reasonably installed and operated on the source type under construction. A technology that is available and applicable is technically feasible.

The Manual provides some guidance for determining availability. For example, a control is generally considered available if it has reached the licensing and permitting stages of development. However, the Manual further provides that a source would not be required to experience extended time delays or resource penalties to allow research to be conducted on new technologies. In addition, the applicant is not expected to experience extended trials learning how to apply a technology on a dissimilar source type. Consequently, technologies in the pilot scale testing stages of development are not considered available for BACT.

As mentioned before, the Manual also requires available technologies to be applicable to the source type under construction before a control is considered technically feasible. For example, deployment of the control technology on the existing source with similar gas stream characteristics is generally a sufficient basis for concluding technical feasibility. However, even in this instance, the Manual would allow for an applicant to make a demonstration on the contrary. For example, an applicant could show that unresolved technical difficulties with applying a control to the source under consideration (e.g., size of the unit, location of the proposed site, and operating problems related to the specific circumstances of the source) make a control technically infeasible.

---

[1] The discussion of the core requirements is taken from the Preamble to the Proposed NSR Reform, 61 FR 38272.

[2] Discussion on technical feasibility is taken from the PSD Final Determination for AES Londonberry, L.L.C., Rockingham County, New Hampshire, authored by the U.S. EPA Region I, Air Permits Program.

According to the Environmental Appeals Board (see In re: Kawaihae Cogeneration Project, 7 E.A.D. 107 at page 1996, EAB 1997), the section on "collateral environmental impacts" of a proposed technology has been interpreted to mean that "if application of a control system results directly in the release (or removal) of pollutants that are not currently regulated under the Act, the net environmental impact of such emissions is eligible for consideration in making the BACT determination." The Appeals Board continues, "The Administration has explained that the primary purpose of the collateral impacts clause is… to temper the stringency of the technological requirements whenever one or more of the specified collateral impacts – energy, environmental, or economic – renders the use of the most effective technology inappropriate." Lastly, the Appeals Board states, "Unless it is demonstrated to the satisfaction of the permit issuer that such unusual circumstances exist, then the permit applicant must use the most effective technology."

The five steps of a top-down BACT review procedure identified by EPA per BACT guidelines are listed below:

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

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

Federal Rule – 40 CFR 60 Subpart Db

Boiler B002 was constructed prior to June 19, 1984, but does have a boiler rating greater than 100 MMBtu/hr. The unit may therefore become subject to 40 CFR 60 Subpart Db – *"Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units"* if this project constitutes a modification or reconstruction.

An NSPS modification is triggered if a project increases the amount of any air pollutant (to which a standard applies) emitted into the atmosphere by that facility or which results in the emission of any air pollutant (to which a standard applies) into the atmosphere not previously emitted. 40 CFR 60.14 elaborates on the general definition of "modification" in 40 CFR 60.2 by defining how the emission rate change due to the project is defined.

The proposed Boiler B002 upgrades will not cause the emissions of new air pollutants into the atmosphere. The NO_X and PM emissions of Boiler B002 are currently limited to 0.30 pounds per million BTU and 0.108 pounds per million BTU in accordance with Condition 3.3.11. The requested NO_X and PM emission rates for this project when firing solid fuels (wood waste, biomass materials, etc) are 0.28 pounds per million BTU and 0.03 pounds per million BTU, respectively. The requested PM emission rate for this project when firing oil is 0.024 pounds per million BTU. The SO_2 emissions for combustion of No. 2 fuel oil are limited to 0.34 percent sulfur by weight. The SO_2 emissions for combustion of any other fuel (i.e., wood waste/biomass) are limited to 3.0 percent sulfur by weight.

The heat input capacity of Boiler B002 will not be changed as part of this project and will remain at 216 million BTU per hour. Boiler B002 is currently capable of operating at the maximum heat input capacity of 216 million BTU per hour but cannot sustain that capacity for extended durations.

The facility claims that actual hourly mass-based emissions for PM and NO_X (in pounds per hour) at maximum actual capacity of this boiler will decrease as result of this upgrade project. The Division will require the facility to conduct a post modification performance test for PM and NO_X emissions, and compare the results with the last Division approved performance test. If the comparison of the performance test results show that hourly emissions (in pounds per hour) increase for PM and NO_X, this boiler upgrade project will constitute a "modification" under NSPS, and Boiler B002 will be subject to all the requirements of 40 CFR 60 Subpart Db.

An evaluation of whether the project meets the requirements of "reconstruction" is also performed. "Reconstruction" under NSPS means the replacement of components of an existing facility to such an extent that the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost required to construct a comparable entirely new facility. The total cost of the Boiler B002 upgrade project is estimated at $3 million. Based on a budget quotation of $8.1 million obtained recently by P&G for a 60,000 lb/hr capacity turn-key boiler project at the Albany Plant and a scale-up cost factor of 0.6, a new boiler facility similar in size to Boiler B002 is estimated to cost over $14 million[3]. Because the $3 million cost of the Boiler B002 upgrade is less than 22 percent of the projected new boiler cost of $14 million, the Boiler 2 upgrade project is not classified as "reconstruction" under 40 CFR 60.15.

State and Federal – Startup and Shutdown and Excess Emissions

Excess emission provisions for startup, shutdown, and malfunction are provided in Georgia Rule 391-3-1-.02(2)(a)7. Excess emissions from the Boiler B002 associated with the proposed project would most likely results from a malfunction of the associated control equipment. The facility cannot anticipate or predict malfunctions. However, the facility is required to minimize emissions during periods of startup, shutdown, and malfunction.

Federal Rule – 40 CFR 64 – Compliance Assurance Monitoring

Under 40 CFR 64, the *Compliance Assurance Monitoring* Regulations (CAM), facilities are required to prepare and submit monitoring plans for certain emission units with the Title V application. The CAM Plans provide an on-going and reasonable assurance of compliance with emission limits. Under the general applicability criteria, this regulation applies to units that use a control device to achieve compliance with an emission limit and whose pre-controlled emissions levels exceed the major source thresholds under the Title V permitting program. Although other units may potentially be subject to CAM upon renewal of the Title V operating permit, such units are not being modified under the proposed project and need not be considered for CAM applicability at this time.

40 CFR 64 – "Compliance Assurance Monitoring" (CAM) applies to pollutant-specific emission units (PSEUs) as defined in the subpart. PSEUs are units for which there exists an emission standard for which there is a Part 64 control device and where the pre-control potential emission rate is equal to or greater than 100 percent of the major source threshold. The frequency of data collection under Part 64 depends on whether the controlled potential to emit exceeds 100 tons per year, in which case it is considered to be a "large PSEU."

CAM requirements will apply to Boiler B002 because the pre-control emissions of PM exceed 100 tons per year and a wet ESP will be employed to control the PM emissions at the PSD avoidance limit of 0.03 lb/MMBTU heat input. Boiler B002 is not considered a large PESU because the post-control emissions are below 100 tons per year.

Therefore, this applicability evaluation only addresses Boiler B002, which employs a Wet Electrostatic Precipitator (Source Code: B002ESP) to control PM emissions. Based on this analysis, P&G has submitted a CAM Plan that describes the general and performance criteria for 2 performance indicators. The CAM Plan is included in Permit Conditions 5.2.7 and 5.2.8 in this permit.

---

[3] $\frac{Cost1}{Cost2} = \left(\frac{Size1}{Size2}\right)^{Scale\,Factor}$

4.0 CONTROL TECHNOLOGY REVIEW

The proposed project will result in increased emissions of a number of pollutants, including CO, lead, NO_X, $PM/PM_{10}/PM_{2.5}$, SO_2, and VOC. However, only the increased emissions for NO_X are significant enough to trigger PSD review.

Boiler B002 - Background

Boiler 2 (Source Code B002) is a waste fuel boiler. It was manufactured and installed in 1981. The unit is currently permitted to fire No. 2 fuel oil, plastic, peanut hulls, pecan hulls, fines, and biomass materials comprising of wood waste and agricultural and forest refuse.

This boiler is equipped with a wet electrostatic precipitator (Source Code: B002ESP) for controlling PM emissions. This control device was installed in 1989 and is a McGill AirClean Model 3-350 unit. It is composed of six Model 175 modules, a quench chamber, and exhaust stack. The components exposed to wet flue gas are made of 316L stainless steel.

The emissions review for the Boiler B002 upgrade project indicates a net NO_X emissions increase of 155 tons per year. Because only NO_X emissions increase from Boiler B002 has triggered PSD applicability, only NO_X emissions were evaluated for Best Available Control Technology (BACT). The increase in CO, lead, $PM/PM_{10}/PM_{2.5}$, SO_2, and VOC emissions from this modification do not exceed the PSD significant modification thresholds; therefore CO, lead, $PM/PM_{10}/PM_{2.5}$, SO_2, and VOC emissions from Boiler B002 were not evaluated for BACT-level controls.

NO_x emitted by combustion processes are contributed by two main sources: 1) nitrogen present in the fuel, and 2) thermal NO_x formed during the combustion process. Approximately 10 to 60 percent of the nitrogen present in a fuel combusted can be oxidized to nitrogen oxide (NO) during the combustion process. The factors that affect the conversion of fuel-bound nitrogen to NO are the availability of oxygen, temperature, and the amount of nitrogen being introduced by the fuel. Fuel-lean conditions promote the formation of NO_x from fuel-bound nitrogen and fuel-rich conditions retard the NO_x formation. The air-fuel mixing affects the production of NO_x by increasing the availability of oxygen that can react with fuel-bound nitrogen forming NO, as opposed to the fuel-bound nitrogen forming elemental nitrogen. Temperature has little known effect on the production of fuel-bound NO_x. Finally, the amount of nitrogen being introduced in the fuel also affects the production of fuel-bound NO_x. At higher fuel input rates, greater NO_x emissions are generated, and conversely lower NO_x emissions are generated at lower fuel rates.

Thermal NO_X formation is a more complex process involving local concentrations of oxygen and nitrogen and is reduced by minimizing the availability of oxygen during the early stages of the combustion process. Thermal NO_x is formed when ambient air is heated in a combustion chamber to a temperature in excess of 2800° F. The elemental oxygen and nitrogen combine to form NO. The high temperatures typically found in a boiler combustion zone exceed the temperature threshold at which thermal NO_x is generated. The reaction between nitrogen and oxygen requires a continuous energy input for the reaction to be sustained. However, the reaction kinetics can be altered through controlling either the availability of oxygen (and likewise nitrogen), or by reducing the flame temperature within the boiler. By controlling either (or both) of these factors, the generation of thermal NO_X can be reduced.

<u>Boiler B002 – NO_x Emissions</u>

<u>Step 1: Identify all control technologies</u>

The NO_X control technologies for boilers are grouped under two main categories; the furnace configuration and combustion controls, and add-on or post-combustion flue gas treatment.

The furnace configuration and combustion controls category includes measures that limit the formation of NO_X in the combustion zone. The specific technologies available under this category are:

- Overfire air (OFA) or staged combustion
- Low NO_X burners
- Flue gas recirculation (FGR)
- Low excess air (LEA) operation
- On-going work practice measures (such as continuous monitoring of combustion system parameters) and proper operation and maintenance practices

The post-combustion flue gas treatment technologies reduce NO_X emissions by promoting the conversion of the flue gas NO_X to nitrogen gas. The available post-combustion NO_X control technologies for boilers include Selective Catalytic Reduction (SCR) and Selective Non-Catalytic Reduction (SNCR).

Step 2: Eliminate technically infeasible options

The technical feasibility evaluation step determines the potential of applicability of the available control system for the specific application. The evaluation process takes into account the design and operating characteristics of the source being controlled and other factors relevant to the application of the available NO_X control system.

The furnace configuration and combustion controls technologies reduce NO_X by utilizing the furnace design configurations and combustion process conditions that minimize the conversion of fuel bound nitrogen to NO_X and formation of thermal NO_X. The individual technologies under this category employ variation of techniques that control the NO_X formation by limiting the availability of oxygen in the critical zones and promoting combustion at lower temperatures. The level of reduction achieved varies with the technology utilized and also depends upon the boiler design.

Overfire Air (OFA)
An OFA system employs a staged combustion technique to reduce NO_X formation by diverting a portion of the combustion air through separate ports located higher in the furnace, in an area where combustion occurs at lower peak temperatures. This technique results in reduction of both fuel NO_X and thermal NO_X. Primary air is mixed with the fuel producing a relatively low temperature, oxygen deficient, fuel-rich zone. In this manner, moderate amounts of fuel NO_X are formed because the fuel nitrogen liberated in this primary combustion zone has little or no free oxygen with which to bond. Therefore, the fuel nitrogen mostly recombines to N_2.

The diversion of the remaining combustion air further downstream in a secondary combustion zone ensures complete combustion, while reducing the temperature of the combustion products. This results in reduction of the thermal NO_X. The secondary air is injected above the combustion zone through a special wind-box with air introducing ports and/or nozzles, mounted above the burners.

OFA system upgrade has been determined to be a technically feasible NO_X control technology for Boiler B002.

Low NO_X Burners
Low NO_X burners are well suited for boilers firing gas and oil. This option has been determined to be technically infeasible for Boiler B002 because the boiler is a stoker design unit where fuel combustion mainly takes place on a stoker bed.

Flue Gas Recirculation (FGR)
FGR NO_X control technology includes recirculation of flue gas into the furnace or into the burner. Mixing of 20 to 30 percent of the flue gas with the combustion air decreases the combustion zone temperature, thereby reducing the thermal NO_X formation. FGR is technically not beneficial for the boilers firing biomass fuels where a significant portion of the NO_X emissions result from fuel nitrogen, as compared to NO_X emissions from thermal NO_X formation. Additionally, use of FGR with OFA systems can result in degradation of the NO_X reduction performance of the OFA technology.

FGR is determined to be technically not feasible for Boiler B002.

Low Excess Air (LEA) Operation
The LEA operation can provide limited NO_X control by limiting the amount of oxygen available for formation of thermal NO_X. The LEA operation can result in incomplete and unstable combustion process that can lead to higher CO emissions, lower boiler efficiency, and increased corrosion and fouling. Also, similar to the FGR option, the LEA option is technically not beneficial for the boilers firing biomass where significant portion of the NO_X emissions result from fuel nitrogen. Therefore, the LEA operation option is technically not feasible for Boiler B002.

Good Combustion and Work Practice Measures
The facility has proposed good combustion and work practice measures as a part of the Boiler B002 BACT strategy. The good combustion and work practice measures include as follows:

- Control of combustion temperature
- Optimum excess air operation
- Boiler tuning
- Monitoring of combustion system parameters to optimize the combustion process

Control of combustion temperature and optimum excess air operation will contribute towards the reduction of thermal NO_X by continuously maintaining the combustion zone temperatures at optimum levels. Boiler tuning and maintenance at regular intervals contribute to superior on-going emissions performance. The in-place operating and management systems at the plant will ensure an emission-efficient performance of Boiler B002.

Instrumentation and controls allow operators to take immediate corrective actions when deviations from preset conditions occur, ensure long-term emission-efficient operation of the boiler. The scope of the Boiler B002 upgrade project includes upgrade of the current controls. The objective of the controls upgrade is to allow the operator a fully automatic, “single knob” control of the boiler. The proposed control upgrade will greatly reduce dependency on operator expertise, variation from shift to shift, steam disruptions due to operator inexperience, and delayed responses inherent in the combustion process. These improved operating capabilities will also enhance the on-going emission performance of the boiler.

In addition to the combustion control measures identified above, the facility also employs work practice measures consisting of operator training and routine equipment maintenance practices. These in-place work practice measures complement the combustion control measures resulting in superior overall NO_X emission performance for Boiler B002.

Selective Catalytic Reduction (SCR)
SCR systems, which are typically installed on large fossil-fuel fired boilers, use a catalyst and a ammonia reductant to dissociate NO_X to nitrogen gas and water vapor. In practice, ammonia injection pipes, nozzles, and mixing grids are located upstream from the catalyst chamber. After a dilute ammonia-air mixture is injected into the flue-gas stream, dispersion occurs, and the catalytic reaction is completed within the catalyst chamber. This technique is used worldwide where high (70 to 90 percent) NO_X removal efficiencies are required.

The theoretical ammonia consumption rate in SCR equals 1 mole of ammonia per mole of NO_X reduction. However, in practice, the actual mole ratio is slightly higher than the one-to-one ratio to account for unreacted ammonia. This excess ammonia is known as ammonia slip. It is desirable to keep ammonia slip levels low because ammonia can react with other combustion constituents such as sulfur trioxide to form ammonium salts. These salts are often in the form of very fine particles that can result in additional PM emissions. Because these particles are also sticky and corrosive, they can potentially cause downstream problems including plugging.

The flue gas stream temperature must be in the 550°F to 750°F range for effective operation of the SCR system. To prevent catalyst blinding, the best possible location of an SCR system for Boiler B002 would be downstream of the wet electrostatic precipitator. However, the temperature of the flue gas stream exiting the wet electrostatic precipitator is normally under 200°F, which is well below the required operating range of the SCR system.

Boiler B002 is also an existing installation that will require retrofitting the control system if the SCR is installed. The current boiler system layout poses retrofit difficulties for the SCR option. In addition, the SCR option will require storage and handling of ammonia and it will require implementation of the safety system plan for ammonia. These factors can significantly increase the overall cost of this boiler upgrade project. Therefore, for all the reasons described above, the SCR option is not technically feasible for Boiler B002.

Selective Non-Catalytic Reduction (SNCR)
SNCR uses a reducing agent such as ammonia or urea to dissociate NO_X to nitrogen gas and water vapor. The reducing agent is injected and mixed into the post-combustion flue gas stream within a specific temperature zone. The reagent can react with a number of flue gas components. However, the NO_X reduction reaction is favored over other chemical reaction processes for a specific temperature range and in the presence of oxygen; therefore, it is considered a selective chemical process.

The acceptable flue gas temperature range for the SNCR reduction reaction is 1,400 to 2,000 ºF, with preferred temperatures of above 1,700ºF. At temperatures below 1,600 ºF, chemical enhancers such as hydrogen are often required to assist the reaction. Above 2,000 ºF, the ammonia or urea may react with available oxygen to form additional NO_X.

Mechanical components required to implement SNCR consist of storage and handling equipment for the ammonia or urea, equipment for mixing the reducing agent with a carrier (compressed air, steam, or water), and the injection equipment. Under carefully controlled conditions, reduction levels of 70 percent are possible, but reductions in the range of 30 to 50 percent are more typical.

Similar to the SCR systems, injection of excess ammonia or urea can create operational problems. Ammonium salts can be produced when excess reducing agent reacts with flue-gas constituents, such as sulfur trioxide. These salts, which may include ammonium sulfate and ammonium bisulfate, can pose undesirable consequences, such as the formation of fine PM, fouling, or corrosion.

SNCR systems have been installed on industrial boilers for controlling NO_X emissions. In Georgia, Langboard MDF – Willacoochee operates a fluidized bed energy system, whose NO_X emissions are controlled by SNCR for PSD avoidance purposes. However, the combustion and temperature profile of the fluidized bed design at Langboard MDF is significantly different than the Boiler B002 design with OFA. The proposed upgrade of Boiler 2's OFA system will result in a lower operating temperature profile for Boiler B002 and is expected to be well below the recommended temperature range of 1,700 ºF to 2,000 ºF.

The facility has determined that SNCR is technically infeasible for controlling Boiler B002 NO_X emissions for several reasons. In addition to the applicability issues discussed above, the expected NO_X reduction of 30 to 50 percent for an SNCR will be comparable to the proposed Boiler 2 BACT strategy consisting of OFA and good combustion practices. Additionally, the Boiler B002 firing rate is expected to fluctuate significantly during normal operation in response to the steam demand of the paper machines. The boiler load fluctuations will make it difficult to operate the SNCR system at optimum levels resulting in degradation of NO_X control performance.

Emerging NO_X Control Technologies

Advances in NOx flue-gas treatment technology are focusing on the development of alternatives to ammonia-based methods. Although generally more expensive than SCR or SNCR systems, these methods are being considered because they do not require on-site storage of ammonia, avoid ammonia permitting issues, and eliminate ammonia slip.

The emerging technologies are being researched for simultaneous control of multiple pollutants, including NO_X. Several proprietary technologies are currently in various stages of development. The technical feasibility of emerging technologies is currently being researched for large coal-fired utility boilers and there are <u>no technically feasible</u> emerging technologies for boiler installations similar to Boiler 2.

<u>Step 3: Ranking the Remaining Control Technologies by Control Effectiveness</u>

The technical feasibility evaluation of NO_X control measures for Boiler B002 indicates that a combination strategy consisting of OFA system improvements and good combustion practices is the technically feasible NO_X control technology for Boiler B002.

<u>Step 4: Evaluating the Most Effective Controls and Documentation</u>

The facility indicates that the OFA system improvements and good combustion practices is the most effective NO_X control strategy for Boiler B002. The OFA system is an integral part of the boiler design and will respond better to the expected load fluctuations and changing operating conditions. The upgraded controls and in-place operating practices will work well in conjunction with the upgraded OFA system.

<u>Step 5: Selection of BACT</u>

The facility indicates that the OFA system improvements and good combustion practices are the most effective NO_X control strategy for Boiler B002.

The control technology review submitted by the facility includes a summary of NO_X BACT measures at existing installations. This summary included the BACT determinations available in EPA's RACT/BACT/LAER Clearinghouse (RBLC) on-line database and recent PSD permit applications processed by the Division. BACT determinations for 7 boiler installations in Georgia and 6 other boiler installations were compared.

Good combustion practices, OFA, and boiler design were the measures accepted as a result of the NO_x BACT review for all except for one determination (Del-Tin Fiber LLC). The Del-Tin Fiber LLC installation indicated SNCR and low NO_X burners as BACT; however, this boiler is subject to a 0.30 lb/MMBtu NO_x limit that is higher than the NO_X emission rate for installations employing combustion controls and good combustion practices. The conclusions of the BACT review at similar installations were as follows:

- The lowest allowable NO_X emission rate for the determinations reviewed was 0.25 lb/MMBtu and it was indicated for 4 installations. However, the facility indicated that the design of these boilers was different from that of Boiler B002. The facility indicated that new boiler installations can achieve lower NO_X emission rates because all combustion system components can be optimally designed. For existing boilers, achieving performance similar to the new units is not possible without a total replacement of all systems affecting the NO_X performance.

- Four installations indicate an allowable emission rate of 0.30 lb/MMBtu.
- The allowable NO_X emission rates for two installations were 0.40 and 0.45 lb/MMBtu.

The review of controls at existing installations indicates that the BACT strategy proposed for Boiler B002 is consistent with the BACT determinations at similar installations. The proposed NO_X limit of 0.28 lb/MMBtu heat input for Boiler B002 is consistent with the NO_X emissions performance data indicated in the BACT determinations.

Based upon the top-down BACT review and review of the control technologies at existing installations submitted by the facility, the OFA system in conjunction with good combustion and work practice measures represents the BACT for the Boiler B002 upgrade project. The use of the proposed BACT strategy will allow Boiler B002 to comply with the proposed NO_X emission rate of 0.28 lb/MMBtu.

Conclusion –NO_x Control

The Division has determined that P&G’s proposal to use the OFA system in conjunction with good combustion and work practice measures to minimize the emissions of NO_X constitutes BACT. The NO_X emission limit for Boiler B002 will be 0.28 lb/MMBTU heat input on a rolling 30-day basis and will include all periods of boiler firing, including startup, shutdown, and malfunction.

Summary –NO_x Control Technology Review for Boiler B002

To fulfill the PSD permitting requirements for NO_X, a BACT analysis was conducted for Boiler B002. The BACT selection for Boiler B002 is summarized below in Table 4-2:

Table 4-2: BACT Summary for the Proposed Modified Boiler B002

Pollutant	Control Technology	Proposed BACT Limit
NO_X	OFA system in conjunction with good combustion and work practice measures	0.28 lb/MMBTU heat input for any 30-day period

5.0 TESTING AND MONITORING REQUIREMENTS

Testing Requirements:

Boiler B002 will be required to undergo initial performance testing for CO, NO_X, and PM upon completion of the upgrade project in accordance with Conditions 4.2.7 and 4.2.8. The initial performance test for NO_X and PM will be used to show that post modification emissions (in pounds per hour) will not increase as a result of this upgrade project. The facility will compare the post modification emissions rates for NO_X and PM (in pounds per hour) with the last pre-modification Division approved performance test. If the test data shows emissions have increased, then this boiler upgrade project will constitute a "modification" under 40 CFR 60.14, and Boiler B002 will be subject to all the requirements for 40 CFR 60 Subpart Db.

Performance testing for NO_X is required to demonstrate compliance with the new proposed NO_X BACT limit. Testing for CO and PM is required to demonstrate compliance with their respective PSD avoidance limits. No initial SO_2 performance test is required for burning fuel oil because Boiler B002 can only burn fuel oil with a sulfur content of 0.34 percent or less in accordance with existing Condition 3.3.10. SO_2 emissions from wood waste, peanut hull, peacan hull, fines and biomass materials are insignificant; thus, no SO_2 testing is required for solid fuels. No initial VOC testing is required because potential VOC emissions from Boiler B002 are only 11 tons per year, and this boiler will be able to easily meet the 0.017 pounds per million Btu PSD avoidance limit.

Existing Condition 4.2.3 requires the facility to test for NO_X and PM emissions on Boiler B002 every 2 years; thus, this condition will continue to require periodic testing for NO_X and PM emissions. No periodic testing is needed for CO emissions.

New Condition 4.2.9 requires the facility to conduct a performance test for acrolein emissions on Boiler B002 to show compliance with the 0.75 pounds per hour limit in Condition 3.4.5. This limit has directly come from the Division's review of the Toxic Impact Assessment for this boiler upgrade project.

Monitoring Requirements:

The facility currently only monitors the average voltage on the WESP. New Conditions 5.2.2.h and 5.2.2.i require the facility to monitor the average secondary current and the average total power on the Wet Electrostatic Precipitator (Source Code: B002ESP). WESP's performance is directly related to total power, and WESP performance increases as total power is increased. Thus, it is necessary to monitor the secondary voltage and the secondary current to calculate the total power. Thus, monitoring of the secondary current, secondary voltage, and the average total power are needed to maintain proper operation of the WESP and to provide reasonable assurance of compliance with the PSD limits. The pre-quench chamber water flow rate for the WESP is also monitored for proper operation of this control equipment. Condition 6.1.7.c.ii is updated to report excursions based on the average total power instead of the secondary voltage for the WESP.

Existing Conditions 5.2.3.a, 5.2.4.a, and 5.2.6.a are updated with the correct reference test method to *ASTM D 6522*, as test method *CTM-30* is no longer valid.

Condition 5.2.3.c is updated with the correct test method and it requires measurement of NO_X and oxygen concentrations for Boiler B002 according to *ASTM D 6522 – Standard Test Method for Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions from Natural Gas-Fired Reciprocating Engines, Combustion Turbines, Boilers, and Process Heaters Using Portable analyzers.* The required frequency of measurement in the condition is once per calendar quarter (quarters ending March 31, June 30, September 30 and December 31). This condition will continue to apply upon completion of the Boiler 2 upgrade.

New Condition 5.2.6 also requires measurement of CO concentrations for Boiler B002 according to *ASTM D 6522 – Standard Test Method for Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions from Natural Gas-Fired Reciprocating Engines, Combustion Turbines, Boilers, and Process Heaters Using Portable analyzers.* Again, the required frequency of measurement in the condition is once per calendar quarter, which is similar to monitoring on Boiler B003. This CO monitoring will provide reasonable assurance of compliance with the PSD avoidance limit.

The facility has submitted a CAM plan with this Title V Application For Boiler B002. Conditions 5.2.7 and 5.2.8 lists the CAM requirements for Boiler B002. CAM requirements is applicable to Boiler B002 because the pre-control emissions of PM exceed 100 tons per year and a wet electrostatic precipitator is used to control the PM emissions. The facility will properly monitor the average voltage, the average current and the total power for the precipitator and the prequench chamber water flow rate to ensure proper operation of the Wet Electrostatic Precipitator (Source Code: B002ESP).

CAM Applicability:

The Boiler B002 is subject to the requirements of compliance assurance monitoring (CAM) as specified in 40 CFR 64. CAM is only applicable to emission units that have potential emissions greater than the major source threshold, located at a major source, use a control device to control a pollutant emitted in an amount greater than the major source threshold for that pollutant, and have a specific emission standard for that pollutant. The Boiler B002 uses a Wet Electrostatic Precipiator (Source Code: B002ESP) to control PM emissions. CAM requirements will apply to Boiler B002 because the pre-control emissions of PM exceed 100 tons per year and this control device will reduce PM emissions to less than the PSD avoidance limit of 0.03 lb/MMBTU heat input. Boiler B002 is not considered a large PESU because the post-control emissions are below 100 tons per year.

In this permit application, P&G has submitted a CAM Plan that describes the general and performance criteria for 2 performance indicators, the average voltage across the wet electrostatic precipitator and the prequench chamber water flow rate. The Division has changed the first performance indicator to average secondary voltage, secondary current, and total power and added a verification of operational status requirement to ensure compliance with emissions limits. The CAM Plan is included in Permit Conditions 5.2.7 and 5.2.8 in this permit.

6.0 AMBIENT AIR QUALITY REVIEW

An air quality analysis is required to determine the ambient impacts associated with the construction and operation of the proposed modifications. The main purpose of the air quality analysis is to demonstrate that emissions emitted from the proposed modifications, in conjunction with other applicable emissions from existing sources (including secondary emissions from growth associated with the new project), will not cause or contribute to a violation of any applicable National Ambient Air Quality Standard (NAAQS) or PSD increment in a Class I or Class II area. NAAQS exist for NO_2, CO, $PM_{2.5}$, PM_{10}, SO_2, Ozone (O_3), and lead. PSD increments exist for SO_2, NO_2, and PM_{10}.

The proposed project at the P&G triggers PSD review for NO_X. An air quality analysis was conducted to demonstrate the facility's compliance with the NAAQS and PSD Increment standards for NO_X. An additional analysis was conducted to demonstrate compliance with the Georgia air toxics program. This section of the application discusses the air quality analysis requirements, methodologies, and results. Supporting documentation may be found in the Air Quality Dispersion Report of the application and in the additional information packages.

Modeling Requirements

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

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

Significance Analysis: Ambient Monitoring Requirements and Source Inventories

Initially, a Significance Analysis is conducted to determine if the NO_X emissions increases at the P&G would significantly impact the area surrounding the facility. Maximum ground-level concentrations are compared to the pollutant-specific U.S. EPA-established monitoring significant level (MSL). The MSL for the pollutants of concern are summarized in Table 6-1.

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

The significant impact analysis for NO_X for the Boiler B002 project indicated ambient impacts below MSL. Therefore, no further modeling for the project was required.

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

Since the predicted modeled impact for the Boiler B002 project was below the monitoring *de minimis* concentration, this project will not require the pre-construction ambient monitoring requirement.

If any off-site pollutant impacts calculated in the Significance Analysis exceed the MSL, a Significant Impact Area (SIA) would be determined. The SIA encompasses a circle centered on the mill with a radius extending out to (1) the farthest location where the emissions increase of a pollutant from the project causes a significant ambient impact, or (2) a distance of 50 km, whichever is less. All sources within a distance of 50 km of the edge of a SIA are assumed to potentially contribute to ground-level concentrations within the SIA and would be evaluated for possible inclusion in the NAAQS and PSD Increment analyses.

Table 6-1: Summary of Modeling Significance Levels

Pollutant	Averaging Period	PSD Significant Impact Level (ug/m^3)	PSD Monitoring Deminimis Concentration (ug/m^3)
NO_X	Annual	1	14

Modeling Methodology

Selection of Model

Two levels of air quality dispersion model sophistication exist: screening and refined dispersion modeling. Normally, screening modeling is performed to determine the need for refined modeling. When results from a screening model indicate potentially adverse impacts, a refined modeling analysis is performed. A refined modeling analysis can provide a more accurate estimate of a source's impact and requires more detailed and precise input data than does a screening model. Given the magnitude of emissions increases from the proposed project, refined modeling was relied upon to predict impacts.

A refined dispersion model requires several data inputs, including the quantity of emissions, meteorological history, and the initial conditions (e.g., velocity, flowrate, and temperature) of the stack exhaust to the atmosphere. Building structures that obstruct wind flow near emission points might cause stack discharges to become caught in the turbulent wakes of these structures, leading to downwash of the plumes. In addition, wind blowing around a building creates zones of turbulence that are greater than if the building were absent. These effects of building downwash inhibit dispersion and generally cause higher ground level pollutant concentrations. Therefore, building configurations near emission sources are also a data input into the model.

AMS/EPA Regulatory Model (AERMOD) Version 07026 promulgated by EPA was used for the Boiler B002 air dispersion modeling analyses. The AERMOD modeling system consists of the main AERMOD program and two pre-processors: AERMET and AERMAP. AERMET is used to pre-process the meteorological data required by AERMOD. Surface characteristics in the form of albedo, surface roughness and Bowen ratio, plus the standard meteorological observations (wind speed, wind direction, temperature, and cloud cover) form the AERMET input. AERMET calculates boundary layer parameters and passes meteorological observations to AERMOD. The meteorological interface in AERMOD uses these data from AERMET to generate profiles of the needed meteorological variables.

AERMAP preprocesses terrain data for the project site and vicinity. It uses gridded terrain data obtained from Digital Elevation Model (DEM) files to calculate a representative terrain-influence height(h_c), also referred to as the terrain height scale. The terrain height scale, which is uniquely defined for each receptor location selected in the model run, is used to calculate the dividing streamline height. For each receptor, AERMAP passes the following information to AERMOD: location coordinates for each receptor (x_r, y_r), its height above mean sea level (z_r), and terrain height scale (h_c).

AERMET Site-Specific Inputs

Surface and upper air data and site characteristic factors form the AERMET inputs. Although on-site meteorological data are preferred, no such data are available for the Albany Plant site. The Columbus/Centerville data were used for the modeling analyses.

Site characteristic factors forming the AERMET input consist of albedo, Bowen ratio, and surface roughness length. The albedo is the fraction of total incident solar radiation reflected by the surface back to space without absorption. Typical values range from 0.1 for thick deciduous forests to 0.9 for fresh snow. The daytime Bowen ratio, an indicator of surface moisture, is the ratio of the sensible heat flux to the latent heat flux and is used for determining planetary boundary layer parameters for convective conditions. Midday values for the Bowen ratio range from 0.1 over water to 10.0 over desert. The surface roughness length is related to the height of obstacles to the wind flow and is the height at which the mean horizontal wind speed is zero. Values for surface roughness length range from less than 0.001 meter over a calm water surface to 1 meter over a forest or urban area.

Values for albedo, Bowen ratio, and surface roughness length by season (winter, spring, summer, and autumn) were selected for the meteorological stations representative of the Albany, Georgia site.

AERMAP Inputs

DEM files for quadrants covering the modeling receptor grid were processed using AERMAP. AERMAP generated location coordinates for each receptor (x_r, y_r), its height above mean sea level (z_r), and terrain height scale (h_c) for use by AERMOD.

Receptor Grids

AERMOD predicts ground-level impacts by utilizing a user-defined receptor grid system. The receptor grid system for the Boiler B002 upgrade project modeling analyses consisted of the following grid segments:

- Receptors along the entire property line with a maximum spacing of 100 meters,
- Cartesian receptor grid with a spacing of 100 meters extending to 1,600 meters from the plant center point in all directions, and
- Polar receptor grid with 10 degree angle increment starting at 1,850 meters from the plant center point and extending up to 2,600 meters with a polar ring radius of 250 meter.

In the air dispersion modeling analyses, ground-level concentrations were calculated within 32 Cartesian receptor grids and at receptors placed along the property line. The property line receptors were spaced 100 meters apart, starting at an arbitrary point on the boundary. The property boundary encompasses all area under P&G's control to which the general public does not have access.

The 32 Cartesian grids covered a region extending from all edges of the facility boundary to the point where impacts from the project were determined to be no longer significant. The receptor grids that were used in this analysis included the following:

1. A property line grid (or fine grid) consisting of evenly spaced receptors 100 meters apart that were placed along the respective mill boundary;

2. A fine grid containing receptors spaced 100 meters apart that extended 1.6 kilometer from the plant center point, exclusive of on-site receptors; and

3. A medium polar receptor grid with 10 degree angle increment starting at 1,850 meters from the plant center point and extending up to 2,600 meters with a polar ring radius of 250 meter.

Representation of Emission Sources

Coordinate System

In all PSD modeling analyses input and output files, the location of emission sources, structures, and receptors were represented in the Universal Transverse Mercator (UTM) coordinate system. The UTM grid divides the world into coordinates that are measured in north meters (measured from the equator) and east meters (measured from the central meridian of a particular zone, which is set at 500 km). The central location of the facility is approximately 774.213 km East and 3493.872 km North in Zone 16. Because the area of the facility where structures and emission units are located is flat, a single base elevation was used in the model data files for all sources. The base elevation for the facility is approximately 185 feet (56.4 meters) above sea level.

Source Types and Parameters

The AERMOD dispersion model allows for emissions units to be represented as point, area, or volume sources. For point sources with unobstructed vertical releases, it is appropriate to use actual stack parameters (i.e., height, diameter, exhaust gas temperature, and gas exit velocity) in the modeling analyses. Boiler 2 was modeled as an unobstructed vertical release point source.

A summary of source parameters used in the significance modeling analysis is included in the permit application in Section 5 (Tables 11, 12 and 13) of the PSD Review Documentation Report.

Modeling Results

Table 6-4 show that the proposed project will not cause ambient impacts of NO_X above the MSL. Because the emissions increases from the proposed project result in ambient impacts less than the MSL, no further PSD analyses were conducted for these pollutants.

Table 6-4: Class II Significance Analysis Results – Comparison to MSLs

Pollutant	Averaging Period	Year	UTM East (km)	UTM North (km)	Maximum Impact (ug/m^3)	MSL (ug/m^3)	Significant?
NO_x	Annual	1991	773.894	3494.075	0.96	1	No

Data for worst year provided only.

As indicated in the table above, maximum model impact for NO_X was below the MSL, therefore, a Full Impact Analysis was not required.

Class I Area Analysis

Federal Class I areas are regions of special national or regional value from a natural, scenic, recreational, or historic perspective. Class I areas are afforded the highest degree of protection among the types of areas classified under the PSD regulations. U.S. EPA has established policies and procedures that generally restrict consideration of impacts of a PSD source on Class I Increments to facilities that are located near a federal Class I area. Historically, a distance of 100 km has been used to define "near", but more recently, a distance of 200 kilometers has been used for all facilities that do not combust coal.

The three Class I areas within approximately 200 kilometers of the Albany Plant are the Bradwell Bay, St. Marks, and Okefenokee, located approximately 160 to 180 kilometers to the south and southeast of the facility. The U.S. Fish and Wildlife Service (FWS) is the designated Federal Land Manager (FLM) responsible for oversight of Okefenokee and St. Marks Class I areas. The U.S. Department of Agriculture, Forest Service (FS) is the designated Federal Land Manager (FLM) responsible for oversight of Bradwell Bay Class I area.

The project and pollutant emissions were reviewed with the FLMs. The FLMs indicated that no Class I Area review was necessary for the project based on project emission levels and distances of the Class I Areas from the plant site.

7.0 ADDITIONAL IMPACT ANALYSES

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

Soils and Vegetation

The effect of a proposed project's emissions on local soils and vegetation is often addressed through comparison of modeled impacts to the secondary NAAQS. The secondary NAAQS were established to protect general public welfare and the environment. Impacts below the secondary NAAQS are assumed to indicate a lack of adverse impacts on soils and vegetation. As discussed in Part 6.0 of this determination, the modeled ambient impacts associated with the proposed project are below the MSLs. Therefore, no negative impacts on soils and vegetation are anticipated to result from the implementation of the proposed project.

Growth

The purpose of a growth analysis is to predict how much new growth is likely to occur as a result of the project and the resulting air quality impacts from this growth. No adverse impacts on growth are anticipated from the project since any workforce growth and associated residential and commercial growth that would be associated with the proposed project (expected to be minimal) would not cause a quantifiable impact on the air quality of the area surrounding the facility.

Visibility

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

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

Georgia's SIP and Georgia *Rules for Air Quality Control* provide no specific prohibitions against visibility impairment other than regulations limiting source opacity and protecting visibility at federally protected Class I areas.

No adverse visibility impacts for the project are anticipated because the maximum annual NO_X concentration is less than MSL. The closest airport to the Albany Plant is the Albany Municipal Airport, which is located 12.1 km to the southwest. The closest state park is the Georgia Veterans Memorial State Park, which is approximately 48.3 km to the northeast of the Albany Plant. Section 11 of the EPA reference document states that the NO_X concentrations associated with urban haze and noticeable discoloration of the atmosphere are 60 $\mu g/m^3$ (0.03 ppm) and 94 $\mu g/m^3$ (0.05 ppm), respectively. Given that the maximum modeled annual NO_X concentration was less than the PSD significance level of 1 $\mu g/m^3$ (0.0005 ppm) and this concentration is well below those associated with haze formation, no significant visibility impacts on area parks or airports are anticipated as a result of the project emissions.

The nearest mandatory Class I areas are the Saint Marks National Wildlife Refuge in Florida, Bradwell Bay Wilderness in Florida, and the Okefenokee National Wildlife Refuge and Wilderness Area in Georgia, which are approximately 160 km south, 180 km south-southwest, and 170 km southeast of the Albany Plant site, respectively. Given that the maximum annual NO_X concentration was less than the PSD significance level of 1 $\mu g/m^3$ (0.0005 ppm), no significant visibility impacts are anticipated as a result of the project emissions on any Class I areas.

Georgia Toxic Air Pollutant Modeling Analysis

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

- U.S. EPA Integrated Risk Information System (IRIS) reference concentration (RfC) or unit risk
- Occupational Safety and Health Administration (OSHA) Permissible Exposure Limits (PEL)
- American Conference of Governmental Industrial Hygienists (ACGIH) Threshold Limit Values (TLV)
- National Institute for Occupational Safety and Health (NIOSH) Recommended Exposure Limits (REL)
- Lethal Dose –50% (LD_{50}) Standards

Selection of Toxic Air Pollutants for Modeling

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

For each TAP identified for further analysis, both the short-term and long-term AAC were calculated following the procedures given in Georgia EPD's *Guideline*. Figure 8-3 of Georgia EPD's *Guideline* contains a flow chart of the process for determining long-term and short-term ambient thresholds. P&G referenced the resources previously detailed to determine the long-term (i.e., annual average) and short-term AAC (i.e., 24-hour or 15-minute). The AACs were verified by the EPD. Table 20 in Application No. 17242 summarizes the total emission rates for the proposed boiler upgrade project at the facility.

Determination of Toxic Air Pollutant Impact

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

Initial Screening Analysis Technique

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

Secondary Screening Analysis Technique

For those pollutants that do not pass the initial screening modeling, Georgia TAP Modeling Guidelines recommend additional screening prior to using refined modeling. The second screening technique involves modeling the particular pollutants from each appropriate stack and adding the impact results from each of the stacks. The total impact is then compared to the AAC. That is, a unit emission rate of 1 g/s is modeled from each stack (or representative stack). MGLC impacts from the unit emission rate are scaled using the actual emissions of a particular TAP from a particular stack for each of the modeled stacks using the equation shown below. The impacts from each stack for a particular TAP are then added to reach a total impact, which is then compared to the AAC for that pollutant.

$$Q_2/Q_1 \times (X_1) = X_2$$

where:
Q_1 = the modeled stack emission rate (1 g/s)
Q_2 = the emission rate of individual TAP
X_1 = the MGLC for 1 g/s
X_2 = the MGLC for the individual TAP

For those impacts that are smaller than the appropriate AAC, it can be concluded that no significant impact is anticipated, and further modeling is not necessary. For those pollutants that indicate a significant impact is possible, refined modeling is performed to further evaluate the potential for significant impacts. The majority of the TAPs usually screen out, requiring no refined modeling.

Air Toxics Modeling Summary

P&G submitted the toxic impact assessment with Application No. 17242 in Section 7.0 of the PSD Preview Documentation Report. The Division independently verified the results by conducting toxics modeling. The results of air toxics modeling show conformance with the respective GA EPD Acceptable Ambient Concentrations. Each source of pollutants was modeled using the ISCST3 model. The results of this analysis are summarized in Tables 20 and 21 in Application No. 17242. These tables show levels below the AACs for all compounds except for acrolein for the annual averaging period.

The annual MGLC for acrolein is less than 10 percent higher than the annual AAC, which was based on the IRIS reference. As a result of the analysis, the Division has included new Condition 3.4.5 that will limit acrolein emissions from Boiler B002 to 0.75 pounds per hour. This limit will ensure that the maximum worst case MGLC for acrolein is 0.0192 micrograms per cubic meter, which is 4 percent lower than the annual AAC value of 0.02 micrograms per cubic meter (IRIS reference).

Therefore, the toxic impact assessment conducted in this section, with the 0.75 pounds per hour emission limit for acrolein, indicates that this proposed project will not have a significant impact on ambient air quality with respect to air toxic emissions.

8.0 EXPLANATION OF DRAFT PERMIT CONDITIONS

The permit requirements for this proposed facility are included in draft Permit Amendment No. 2676-095-0071-V-01-7.

Section 1.0: Facility Description

Please refer to Section 2.

Section 2.0: Requirements Pertaining to the Entire Facility

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

Section 3.0: Requirements for Emission Units

New Condition 3.3.11 requires the facility to limit NO_X emissions to less than 0.28 pounds per million BTU heat input for Boiler B002. This is a new PSD limit that comes directly from the facility's BACT review. This facility was previously subject to a NO_X emissions limit of 0.30 pounds per million BTU heat input for Boiler B002.

New Condition 3.3.17 requires the facility to limit PM emissions to less than 0.024 pounds per million Btu, CO emissions to less than 0.0363 pounds per million Btu, and VOC emissions to less than 0.0015 pounds per million Btu, while firing fuel oil in Boiler B002. In this permit application, the facility has requested to take these PSD Avoidance limits for PM, CO and VOC to limit potential emissions of these pollutants while Boiler B002 is firing fuel oil.

New Condition 3.3.18 requires the facility to limit PM emissions to less than 0.03 pounds per million Btu, CO emissions to less than 0.5 pounds per million Btu, VOC emissions to less than 0.017 pounds per million Btu, and SO_2 emissions to less than 0.025 pounds per million Btu, while firing solid fuels in Boiler B002. In this permit application, the facility has requested to take these PSD Avoidance limits for PM, CO, VOC and SO_2 to limit potential emissions of these pollutants while Boiler B002 is firing solid fuels. In accordance with existing Condition 3.2.1, Boiler B002 is only authorized to fire solid fuels, such as biomass (e.g., bark, wood waste, peanut and pecan hulls), paper fines, and plastic.

New Condition 3.3.19 requires the facility to limit fuel oil usage in Boiler B002 to no more than 2,340,000 gallons for any 12-month period. This is a PSD avoidance limit that the facility requested in this permit application to limit potential emissions from this boiler, while firing fuel oil.

New Condition 3.3.20 requires the facility to use the overfire system and good combustion practices to reduce NO_x emissions from Boiler B002. This is a new PSD requirement that comes directly from the facility's BACT review.

New Condition 3.4.5 requires the facility to limit acrolein emissions from Boiler B002 to 0.75 pounds per hour or less. This limit directly comes from the Division's review of the Toxic Impact Assessment for this boiler upgrade project. In order for the facility to successfully pass the toxic impact assessment, a maximum hourly emissions rate for acrolein is included in this permit amendment.

Condition 3.5.4 requires the facility to commence construction on the Boiler B002 upgrade project within 18 months of issuance of the permit amendment.

Section 4.0: Requirements for Testing

New Condition 4.2.7 requires the facility to undergo initial performance testing for NO_X and PM within 180 days upon completion of the upgrade project for Boiler B002. Performance testing for NO_X is required to demonstrate compliance with the new proposed NO_X BACT limit. Performance testing for PM is required to demonstrate compliance with the new respective PSD avoidance limits for firing oil and solid fuels in Conditions 3.3.17 and 3.3.18. Condition 4.2.7 requires the facility to conduct performance tests in accordance with all the requirements in Condition 4.2.3 (a-e). Subsequently, the facility will be required to do periodic testing for NO_X and PM every 2 years. The initial performance test for NO_X and PM will be used to show that post modification emissions (in pounds per hour) will not increase as a result of this upgrade project. The facility will compare the post modification emissions rates for NO_X and PM (in pounds per hour) with the last pre-modification Division approved performance test. If the test data shows emissions have increased, then this boiler upgrade project will constitute a "modification" under 40 CFR 60.14, and Boiler B002 will be subject to all the requirements for 40 CFR 60 Subpart Db.

New Condition 4.2.8 requires the facility to undergo initial performance testing for CO within 180 days upon completion of the upgrade project for Boiler B002. Performance testing for CO is required to demonstrate compliance with the new respective PSD avoidance limit for firing solid fuels in Condition 3.3.18. No periodic testing for CO will be required.

New Condition 4.2.9 requires the facility to conduct a performance test for acrolein emissions to show compliance with the applicable limit in Condition 3.4.5.

Section 5.0: Requirements for Monitoring

The facility currently only monitors the average voltage on the WESP. New Conditions 5.2.2.h and 5.2.2.i require the facility to monitor the average secondary current and the average total power on the Wet Electrostatic Precipitator (Source Code: B002ESP). WESP's performance is directly related to total power, and WESP performance increases as total power is increased. Thus, it is necessary to monitor the secondary voltage and the secondary current to calculate the total power. Thus, monitoring of the secondary current, secondary voltage, and the average total power are needed to maintain proper operation of the WESP and to provide reasonable assurance of compliance with the PSD limits. The pre-quench chamber water flow rate for the WESP is also monitored for proper operation of this control equipment. Condition 6.1.7.c.ii is updated to report excursions based on the average total power instead of the secondary voltage for the WESP.

Existing Conditions 5.2.3.a, 5.2.4.a, and 5.2.6.a are updated with the correct reference test method to *ASTM D 6522*, as test method *CTM-30* is no longer valid.

Condition 5.2.3.c is updated with the correct test method and it requires measurement of NO_X and oxygen concentrations for Boiler B002 according to *ASTM D 6522 – Standard Test Method for Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions from Natural Gas-Fired Reciprocating Engines, Combustion Turbines, Boilers, and Process Heaters Using Portable analyzers.* The required frequency of measurement in the condition is once per calendar quarter (quarters ending March 31, June 30, September 30 and December 31). This condition will continue to apply upon completion of the Boiler 2 upgrade.

New Condition 5.2.6 also requires measurement of CO concentrations for Boiler B002 according to *ASTM D 6522 – Standard Test Method for Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions from Natural Gas-Fired Reciprocating Engines, Combustion Turbines, Boilers, and Process Heaters Using Portable analyzers.* Again, the required frequency of measurement in the condition is once per calendar quarter, which is similar to monitoring on Boiler B003. This CO monitoring will provide reasonable assurance of compliance with the PSD avoidance limit.

The facility has submitted a CAM plan with this Title V Application For Boiler B002. Conditions 5.2.7 and 5.2.8 lists the CAM requirements for Boiler B002. CAM requirements is applicable to Boiler B002 because the pre-control emissions of PM exceed 100 tons per year and a wet electrostatic precipitator is used to control the PM emissions. The facility will properly monitor the average voltage, the average current and the total power for the precipitator and the prequench chamber water flow rate to ensure proper operation of the Wet Electrostatic Precipitator (Source Code: B002ESP).

Section 6.0: Other Recordkeeping and Reporting Requirements

New Condition 6.2.14 requires the facility to track usage of fuel oil and any other solid fuels fired in Boiler B002. Fuel oil usage records are required to show compliance with the new PSD Avoidance limit in accordance with Condition 3.3.19.

Section 7.0: Other Specific Requirements

Condition 7.14.1 is a PSD condition that states this permit will be voided if the facility does not commence construction on this project within 18 months.

APPENDIX A

Draft Revised Title V Operating Permit Amendment
The Procter & Gamble Paper Products Company - Albany
Albany (Dougherty County), Georgia

APPENDIX B

Procter & Gamble Paper Products Company PSD Permit Application and Supporting Data

Contents Include:

1. PSD Permit Application No. 17242, dated February 1, 2007
2. Additional Information Package Dated July 17, 2007 - Boiler B002 Economizer
3. Class I Area Review Emails

APPENDIX C

EPD'S PSD Dispersion Modeling and Air Toxics Assessment Review