Prevention of Significant Air Quality Deterioration Review

Preliminary Determination

January 31, 2010

Facility Name: Mitchell Steam-Electric Generating Plant
City: Albany
County: Dougherty
AIRS Number: 04-13-09500002
Application Number: 18663
Date Application Received: December 18, 2008

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

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SUMMARY

The Environmental Protection Division (EPD) has reviewed the application submitted by Mitchell Steam-Electric Generating Plant for a permit to convert the Mitchell 3 coal-fired unit (155 MW net) to a biomass-fired steam generating unit (96 MW net). The proposed project will convert Mitchell 3 to a biomass-fired steam generating unit and will add a new fuel handling, processing, storage, and delivery system. The steam generating unit conversion will be accomplished by replacing the bottom section of the existing steam generating unit and installing a stoker boiler along with other pressure parts and back-end equipment modifications. This conversion will also include adding a cyclone separator ("multiclone") ash removal system upstream of an existing air preheater, modifying the bottom ash removal system, and replacing the coal yard and coal handling system with a new biomass yard and biomass delivery system.

Mitchell Steam-Electric Generating Plant currently consists of one 155 megawatt (MW) net bituminous coal fired unit (Source Code: SG03) and six simple-cycle combustion turbines operating in pairs with each pair powering a generator rated at 40 MW.

The proposed project will result in an increase in emissions from the facility. The sources of these increases in emissions include the SG03, Steam Generating Unit 3 and WC03, Potential Onsite Wood Chipper.

The modification of the Mitchell Steam-Electric Generating Plant due to this project will result in an emissions increase in PM/PM_{10}, $PM_{2.5}$, CO, VOC and Pb. 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 PM/PM_{10}, $PM_{2.5}$, CO and VOC emissions increases were above the PSD significant level thresholds.

Mitchell Steam-Electric Generating Plant is located in Dougherty County, which is classified as "attainment" or "unclassifiable" for SO_2, $PM_{2.5}$, PM_{10}, NO_X, CO and ozone (VOC).

The EPD review of the data submitted by Mitchell Steam-Electric Generating Plant 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 PM/PM_{10}, $PM_{2.5}$, CO and VOC, 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 300 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 Mitchell Steam-Electric Generating Plant for the modifications necessary to convert the Mitchell 3 coal-fired unit to a biomass-fired steam generating unit. Various conditions have been incorporated into the current Title V operating permit to ensure and confirm compliance with all applicable air quality regulations. A copy of the draft permit amendment is included in Appendix A. This Preliminary Determination also acts as a narrative for the Title V Permit.

1.0 INTRODUCTION – FACILITY INFORMATION AND EMISSIONS DATA

On December 12, 2008, Mitchell Steam-Electric Generating Plant (hereafter Plant Mitchell) submitted an application for an air quality permit to convert the Mitchell 3 coal-fired unit to a biomass-fired steam generating unit. The facility is located at 5200 Radium Springs Road in Albany, Dougherty County.

Table 1-1: Title V Major Source Status

Pollutant	Is the Pollutant Emitted?	If emitted, what is the facility's Title V status for the Pollutant?		
		Major Source Status	Major Source Requesting SM Status	Non-Major Source Status
PM	Yes	✓		
PM_{10}	Yes	✓		
SO_2	Yes	✓		
VOC	Yes	✓		
NO_x	Yes	✓		
CO	Yes	✓		
TRS	No			
H_2S	No			
Individual HAP	Yes	✓		
Total HAPs	Yes	✓		

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

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

Permit Number and/or Off-Permit Change	Date of Issuance/ Effectiveness	Purpose of Issuance
4911-095-0002-V-02-0	February 14, 2006	Title V Renewal Issue
4911-095-0002-V-02-1	October 20, 2008	The use of testing method ASTM D5142 or ASTM D3173 to analyze coal samples for moisture content
4911-095-0002-V-02-2	March 12, 2009	Title V Amendment to update the Title IV Acid Rain Program, Phase II NOx Averaging Plan
4911-095-0002-V-02-3	November 16, 2009	Title V Amendment to incorporate the requirements of 40 CFR 96 for Clean Air Interstate Rule (CAIR) for SO_2 and NOx Annual Trading Programs

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 1-3 below:

Table 1-3: Emissions Increases from the Project

Pollutant	Baseline Years	Potential Emissions Increase (tpy)	PSD Significant Emission Rate (tpy)	Subject to PSD Review
PM	August 2006-July 2008	+164.6	25	**Yes**
PM_{10}	August 2006-July 2008	+164.6	15	**Yes**
$PM_{2.5}$	August 2006-July 2008	+164.6	10	**Yes**
VOC	August 2006-July 2008	+345.5	40	**Yes**
NO_X	August 2006-July 2008	-473.4	40	No
CO	August 2006-July 2008	+2530.0	100	**Yes**
SO_2	May 2006-July 2008	-1082.8	40	No
Pb	August 2006-July 2008	+0.264	0.6	No

Pollutant	Baseline Years	Potential Emissions Increase (tpy)	PSD Significant Emission Rate (tpy)	Subject to PSD Review
Fluorides	August 2006-July 2008	-282.8	3	No
SAM	May 2006-July 2008	-9.0	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 5-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 May 2006 through April 2008 or August 2006 through July 2008) from the future projected actual emissions of the biomass-fired steam generating unit, new fuel handling, processing, storage, and delivery system and associated emission increases from non-modified equipment. Table 1-4 details this emissions summary. The emissions calculations for Tables 1-3 and 1-4 can be found in detail in the facility's PSD application (see Section 2.0 of Application No. 18663).

For the baseline actual emissions calculations, the SO_2 and NOx data was taken from continuous emissions monitoring systems (CEMS) and the emissions of CO and VOC were taken from emissions factors as described in EPA's AP42, Fifth Edition, volume I, Chapter 1: External Combustion Sources, Section 1.6: Wood Residue Combustion in Steam Generating Units (September 2003). Baseline actual emissions for Pb and Fluorides (F), were based on the average lb/mmBtu emission rate derived from the 2006 and 2007 TRI reports for Mitchell 3 applied to the highest baseline heat input for the periods listed in Table 1-3 above. The PM_{10} baseline emissions were based on "as-burned" fuel data and on the unit's historical operating levels and also includes a calculation for condensable PM_{10} emissions. The baseline for H_2SO_4 emissions is derived from SO_2 emission rates. The baseline emissions for H_2SO_4 also take in to account the removal efficiency of downstream equipment such as the air heater and the electrostatic precipitator.

The following analyses were used to determine the maximum potential emissions (or future projected actual emissions) after the conversion of the coal-fired steam generating unit (Source Code: SG03) to biomass. Five categories of biomass fuel will potentially be combusted, including clean wood chips (pine chips, hardwood chips, pallets and reels), whole tree chips (trees, shrubs, unmerchantable fuel wood, and thinnings), tops and limbs (forest residues and bark), manufacturer's residues (sawdust and sanders dust), and hulls (peanut and pecan hulls). All of these fuels are represented by the four fuel analyses that Georgia Power has conducted to determine the potential emission characteristics of these fuels. The four fuel analyses are provided in Appendix A of the application and are listed below:

- T&L Pine (Hazen analysis, August 27, 2008)
- Clean Debarked Pine Chips (Hazen analysis, sample #2, February 26, 2008)
- Clear Cut, 90 Hard/10 Pine (Hazen analysis, sample #3, February 26, 2008)
- Peanut Hulls (CTE analysis, May 21, 1987)

The worst-case fuel analysis is used for each pollutant to determine the potential to emit (PTE) of the unit after the conversion to biomass.

Alstom Power Inc. (Alstom), the original equipment manufacturer for the existing Mitchell 3 Steam Generating Unit performed an engineering study for Georgia Power to evaluate the feasibility of converting this steam generating unit to biomass fuel firing. As part of the study, Alstom provided emission rate estimates for many of the pollutants that would be emitted. Emission parameters are dependent on the specific fuel used, the temperature of combustion, the excess air in the combustion chamber, fuel data, etc., and emission rates were selected as appropriate. Emission rates during normal operation were established for each pollutant based on the Alstom data and other considerations, taking into account the proposed BACT controls and limits. BACT controls and limits as discussed in Section 4.0, are the basis for the CO, VOC and PM_{10} emissions. The emission rates were established for three load points: full load (100% load), intermediate load (72.9%), and minimum load (58.3% load). Table 2.1 of

Section 2.0 of the facility's application contains the emission rates for the PSD air pollutants at the three operating loads.

The highest lb/mmBtu emission rate identified for each pollutant was then multiplied times the maximum heat input (mmBtu/hr) to establish normal operation lb/hr rates. The maximum emission rates for each pollutant were used to determine the maximum potential annual emissions. Emissions from the potential wood chipper diesel engine provided in Section 2.6 of the application were also included in determining the maximum potential annual emissions.

In addition to the direct stack emissions from the biomass steam generating unit and the potential wood chipper diesel engine, there may be VOC emissions from the biomass storage pile due to the turpentine content of green biomass chips. Appendix B of the facility's application details a conservative calculation of annual VOC emissions from the storage pile based on estimated turpentine losses. The maximum potential annual emissions include VOCs emitted from the storage pile and storage pile fugitive emissions.

Sources of particulate matter include direct emissions from the steam generating unit stack, direct emissions from the potential on-site chipper operation (Table 2-4 of application), as well as fugitive emissions from the biomass delivery, storage, and handling system. The worst case for direct filterable PM_{10} emissions will be 0.02 lb/mmBtu. This is based on burning tops and limbs with a maximum ash content of 10 percent and installation of new high frequency power supplies in the existing ESP. It is expected that essentially all of the direct filterable PM will be less than 10 μm (i.e. PM_{10}).

Total PM_{10} is comprised of filterable and condensable emissions. The AP-42 emission factor for the emission of condensable particulate matter from the combustion of biomass is 0.017 lb/mmBtu. Given the limited condensable emissions data available for biomass stoker steam generating units and the uncertainty in the condensables test methods, the AP-42 value was rounded to the second decimal (0.02 lb/mmBtu). Therefore the total PM_{10} emission rate including filterable and condensable PM_{10} emissions is 0.04 lb/mmBtu (52.6 lb/hr).

The maximum emission rate for lead is from AP-42. At normal full load operation the lead emission rate is 0.0631 lb/hr. Lead emissions from the potential wood chipper diesel engine are expected to be negligible as shown in Section 2.6 of the application.

For hydrogen fluoride, total reduced sulfur compounds, chlorinated fluorocarbons (cfcs), and halons, there are no emissions listed in AP-42. Therefore, it is assumed that there are no emissions from these pollutants expected from the biomass conversion project.

Sulfuric Acid Emissions are calculated consistent with the method used by Georgia Power to derive these emissions for Toxics Release Inventory (TRI) purposes. This method is documented in a report from the Electric Power Research Institute (EPRI) entitled "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants: Technical Update, March 2008". Sulfuric acid emissions from the wood chipper diesel engine are negligible due to the use of the ultra-low sulfur diesel fuel. Thus, the total maximum annual sulfuric acid emissions from the biomass project are 5.7 tpy.

The source of the emission factors for most of the hazardous air pollutants (HAPs) is the U.S. EPA AP42, Fifth Edition, Volume 1, Chapter 1: External Combustion Sources, Section 1.6: Wood Residue Combustion in Steam Generating Units (September 2003). If any other sources of emissions data are used, a citation to the alternative source of data is provided.

The facility sites that the typical analyses of mercury in the biomass fuel likely to be burned ranges from 2.5 to 5.5 lb/Tbtu. In an EPA document (http://www.epa.gov/ttn/chief/le/mercury.pdf), emissions rates are given from NCASI documents of between 0.15 and 0.18 lb/TBtu for wood boilers with ESPs. This document also lists rates for uncontrolled wood boilers, and these two numbers imply a collection efficiency of 62 percent for mercury in an ESP of a wood boiler. This seems reasonable given the large amount of unburned carbon typical in wood combustion fly ash which acts like activated carbon. Therefore, the mercury emissions above were calculated based on the expected mercury content of the biomass taking into account the reductions expected from the ESP. Using the high end of the range of expected mercury content (5.5 lb/TBtu) and the 62 percent control efficiency, the resulting emission rate is 2.1 lb/TBtu.

For hydrogen chloride, the analyses for chlorine in the biomass likely to be burned indicates a content that is less than 0.005 percent. Therefore, for conservatism this value was used to calculate a hydrogen chloride emission rate of 0.013 lb/mmBtu by assuming that all of the chlorine in the biomass is emitted as hydrogen chloride.

Table 2-3 of the application, shows the emission factors and annual emissions for Organic HAPs, Metallic HAPs, and Dioxins/Furans. The resulting total annual emission for all HAPs is 187.3 (>25) tons and the facility is classified as a major source for HAPs.

These calculations have been reviewed and approved by the Division.

Table 1-4: Net Change in Emissions Due to the Major PSD Modification

Pollutant	Increase from Modified equipment		Associated Units Increase (tpy)	Total Increase (tpy)
	Past Actual	Future Actual		
PM/PM_{10}	72.2	236.8	-	+164.6
$PM_{2.5}$	72.2	236.8	-	+164.6
VOC	7.4	352.9	-	+345.5
NO_X	1929.1	1455.7	-	-473.4
CO	63.0	2593.0	-	+2530.0
SO_2	4884.2	3801.4	-	-1082.8
Pb	0.013	0.277	-	+0.264
Fluorides	282.2	0	-	-282.2
SAM	14.7	5.7	-	-9.0

Based on the information presented in Tables 1-3 and 1-4 above, Plant Mitchell's proposed modification, as specified per Georgia Air Quality Application No. 18663, is classified as a major modification under PSD because the potential emissions of PM_{10} (164.6>15), $PM_{2.5}$, (164.6>10), VOC (345.5>40) and CO (2530>100) exceed the PSD Significant Emission Rates.

Through its new source review procedure, EPD has evaluated Plant Mitchell'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. 18663, Plant Mitchell has proposed to convert Mitchell 3 to a biomass-fired steam generating unit and will add a new fuel handling, processing, storage, and delivery system. The steam generating unit conversion will be accomplished by replacing the bottom section of the existing steam generating unit and installing a stoker along with other pressure parts and back end equipment modifications. This conversion will also include adding a cyclone separator ("multiclone") ash removal system upstream of an existing air preheater, modifying the bottom ash removal system, and replacing the coal yard and coal handling system with a new biomass yard and biomass delivery system.

Plant Mitchell has proposed to use an onsite chipping operation to supplement the fuel supply as market conditions and fuel supply availability dictate. The facility may proceed with the installation of the onsite chipping operation and (if so) will plan to install an equipment similar to a CBI 8400-P Magnum chipper, driven by a Caterpillar C27 ACERT Model engine with a maximum rated capacity of 1,050 bhp and displacement of 27 liters. The engine will be fired with ultra-low sulfur diesel (ULSD) fuel oil with a maximum sulfur content of 15 ppmw. Based on the maximum processing capacity of the wood chipper of 150 tph, the engine will operate no more than 3,000 hours per year to process a maximum of 450,000 tons of wood annually.

The Plant Mitchell 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 thereunder. Georgia Rule 391-3-1-.03(8)(b) continues that no permit to construct a new stationary source or modify an existing stationary source shall be issued unless such proposed source meets all the requirements for review and for obtaining a permit prescribed in Title I, Part C of the Federal Act [i.e., Prevention of Significant Deterioration of Air Quality (PSD)], and Section 391-3-1-.02(7) of the Georgia Rules (i.e., PSD).

The facility will be subject to the following specific Georgia Rules for Air Quality Control – Chapter 391-3-1:

- Rule 391-3-1-.02(2)(d) – Fuel-burning Equipment: The following limits will apply to the steam generating units:
    - PM_{10}: 0.10 lb/MMBtu
    - NOx: when firing oil—0.3 pounds of NOx per million BTUs of heat input
    - Opacity: 20%, except for one 6-minute period per hour of no more than 27% opacity
    - This rule subsumes rule 391-3-1-.02(2)(b) and is identical to the opacity emission limits of NSPS Subpart Db for the biomass-fired steam generating unit (Source Code: SG03).

  Initial performance testing and operation of the Continuous Opacity Monitoring System (COMS) will be used to demonstrate compliance with this standard.

- Rule 391-3-1-.02(2)(g) – Sulfur Dioxide: The following limit will apply to the biomass-fired steam generating unit (Source Code: SG03).
    - Fuel sulfur content of no more than 3% by weight.

  Initial and period fuel sampling and sulfur content analysis will be used to demonstrate compliance with this standard.

- Rule 391-3-1-.02(2)(n) – Fugitive Dust: The Plant Mitchell facility will be required to take all reasonable precautions to prevent fugitive dust from becoming airborne and to maintain visible emissions from fugitive dust below 20% opacity.

- Note that Rule 391-3-1-.02(2)(jjj) – NO_x Emissions from Electric Utility Steam Generating Units – does not apply because the steam generating unit is not coal-fired and is not located in one of the counties subject to this standard.

- Rule 391-3-1-.02(2)(sss) - Multipollutant Control for Electric Utility Steam Generating Units: The Multipollutant Control for Electric Utility Steam Generating Units would have limited Plant Mitchell to a total annual heat input of 8,621,580 million Btu on coal combustion as of January 1, 2018. However since Plant Mitchell will be converted to biomass before 2018 and will not burn any coal after 2018, the Multipollutant Rule will no longer apply to Plant Mitchell after the facility commences construction on this project.

Federal Rule - PSD

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

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

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

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

Definition of BACT

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

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

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

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

New Source Performance Standards

Part 60, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR Part 60) New Source Performance Standards (NSPS) Subpart A – General Provisions
Except as provided in Subparts B and C of 40 CFR Part 60, the provisions of this regulation apply to the owner or operator of any stationary source which contains an affected facility, the construction or modification of which is commenced after the date of publication in this part of any standard (or, if earlier, the date of publication of any proposed standard) applicable to that facility [40 CFR 60.1(a)]. Plant Mitchell is an existing facility and the proposed converted biomass steam generating unit (Source Code: SG03) is subject to this regulation. Any new or revised standard of performance promulgated pursuant to Section 111(b) of the Clean Air Act apply to this biomass-fired steam generating unit.

In addition to the performance testing requirements of 40 CFR 60.8, 40 CFR 60.7(a)(4) requires notification to the state and federal authorities 60 days before the modification takes place. 40 CFR 60.7(a)(3) similarly requires notification of startup no later than 15 days after modified operations commence. Finally, 40 CFR 60.7(b) requires the facility to maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of an affected facility.

Part 60, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR Part 60) New Source Performance Standards (NSPS) Subpart Db – Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units
Because the proposed steam generating unit will have a heat input capacity of greater than 100 MMBtu/hr and will be constructed, modified, or reconstructed after June 19, 1984, it will be subject to the New Source Performance Standard (NSPS) for Industrial-Commercial-Institutional Steam Generating Units, 40 CFR 60 Subpart Db. Although the biomass steam generating unit will burn distillate oil or biodiesel for startup, the project will not result in an increase in the maximum hourly emission rate of either SO_2 or NO_x, the other two pollutants regulated under Subpart Db (i.e., the SO_2 and NO_x standards in 40 CFR 60.42b and 60.44b, respectively). Only the PM_{10} standards (40 CFR 60.43b) of the NSPS will apply.

Since the steam generating unit will combust over 30 percent wood (by heat input) on an annual basis and will commence modification after February 28, 2005 and has a heat input capacity of greater than 250 MMBtu/hr, it will be subject to a PM_{10} emission limit of 0.085 lb/MMBtu [40 CFR 60.43b(h)(4)]. Also, because the steam generating unit will combust wood, it will be subject to a limit of 20% opacity (6-minute average), except for one 6-minute period per hour of no more than 27% opacity [40 CFR 60.43b(f)]. Also, since the steam generating unit will be subject to an opacity standard under 40 CFR 60.43b, Plant Mitchell will be required to install, calibrate, maintain, and operate a continuous opacity monitoring system (COMS)[40 CFR 60.48b(a)]. The facility will also install a Multiclone (Source Code: MC03) and a dry ESP (Source Code: EP03) and a COMS is now a NSPS requirement for monitoring opacity from the wood steam generating unit (Source Code: SG03).

Also, the NSPS reconstruction criteria are not triggered since the installed cost of a new equivalent wood steam generating unit per the estimate would be approximately $120,012,932. The costs associated with the steam generating unit upgrades are estimated to be $42,210,164, which is far below the 50% reconstruction cost threshold.

Part 60, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR Part 60) New Source Performance Standards (NSPS) Subpart IIII – Standards of Performance Stationary Compression Ignition Internal Combustion Engines

NSPS for Compression Ignition Internal Combustion Engines promulgated under 40 CFR 60, Subpart IIII is potentially applicable to the Biomass Project if a diesel chipping operation is installed. As mentioned in Section 2, Mitchell may construct and operate an onsite chipping operation to supplement the fuel supply. A Caterpillar C27 ACERT Model diesel engine with a maximum rated capacity of 1,050 bhp and displacement of 27.0 liters (2.3 liters per cylinder), resembles the engine that would be purchased. The engine will fire ultra-low sulfur diesel (ULSD) fuel oil and the fuel must meet the requirements of 40 CFR 80.510(b) for nonroad diesel fuel [40 CFR 60.4207(b)]. Based on the maximum processing capacity of the wood chipper of 150 tph, the engine will operate no more than 3,000 hours per year to process a maximum of 450,000 tons of wood annually.

This engine is subject to Section 60.4204 of NSPS IIII that contains the emission standards for owners or operators of non–emergency engines of stationary CI internal combustion engines. Since this engine will be a 2007 model year or later non-emergency stationary CI ICE with a displacement of less than 30 liters per cylinder (this engine has a displacement of 2.3 liters per cylinder), the engine must comply with the emissions standards in 40 CR 60.4201(a). The regulation 40 CR 60.4201(a), refers to 40 CFR 89.112, the oxides of nitrogen, carbon monoxide, hydrocarbon, and particulate matter exhaust emission standards section of "*Control of Emissions from New and In-use Nonroad Compression-Ignition Engines*". For the motor which is rated at 75 kW, the standard references Tier 2 standards, and states that emissions from model year 2007 and later engines with displacement of less than 10 liters per cylinder may not exceed the following values:

(i) 7.5 g/kW-hr for NMHC & NOx

(ii) 5.0 g/kW-hr for CO

(iii) 0.4 g/kW-hr for PM

The engine must be certified for EPA Tier-2 to meet the NSPS IIII requirements of Tier 2 standards.

National Emissions Standards For Hazardous Air Pollutants

As emissions of hydrochloric acid (HCL) are expected to exceed 10 TPY based on the projected usage of the biomass-fired steam generating unit (SG03), Plant Mitchell is considered to be a major source for hazardous air pollutants (HAPs). Since the biomass-fired steam generating unit (Source Code: SG03) does not meet the definition of a "constructed" or "reconstructed" source under 40 CFR Part 63 Subpart B, Section 112(g) does not apply. The site is potentially subject to 112(j). However, GA EPD is currently awaiting written guidance from USEPA on 112(j) applicability. Plant Mitchell will comply with the Industrial Steam Generating Unit MACT once it is re-promulgated. The proposed biomass-fired steam generating unit (Source Code: SG03) is an EGU, as defined in 40 CFR 63.7575, since it does use fossil fuels.

Also, the cost of modifications to the wood steam generating unit does not exceed 50% of the replacement cost, so the steam generating unit is not considered "reconstructed" per the definition in 40 CFR 63.2. Therefore, the steam generating units are existing sources in accordance with NESHAP and are not subject to any new source MACT requirements including "case-by-case" analysis (40 CFR 63 Subpart B).

In 2004, EPA promulgated a MACT standard for Industrial, Commercial, and Institutional Steam Generating Units, which is codified at 40 CFR Part 63, Subpart DDDDD. This standard would likely have become applicable to Plant Mitchell Unit 3 once it was converted to biomass because the unit would no longer be exempt from Subpart DDDDD as a fossil fuel-fired electric utility steam-generating unit. However, the Industrial Steam Generating Unit MACT was vacated by the United States Court of Appeals for the D.C. Circuit in 2007. Therefore Subpart DDDDD, as currently promulgated, will not apply to the project. Plant Mitchell will be required to comply with the Industrial Steam Generating Unit MACT once it is re-promulgated.

Part 63, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR Part 63) National Emission Standards for Hazardous Air Pollutants (NESHAP) for Reciprocating Internal Combustion Engines (RICE) 40 CFR Part 63, Subpart ZZZZ
This regulation is applicable to a stationary RICE as defined in the regulation at a major source of HAP emissions, which is a plant site that emits or has the potential to emit any single HAP at a rate of 10 tons (9.07 megagrams) or more per year or any combination of HAPs at a rate of 25 tons (22.68 megagrams) or more per year [40 CFR 63.6585]

MACT Standard for Reciprocating Internal Combustion Engines (RICE) promulgated under 40 CFR 63, Subpart ZZZZ is potentially applicable to the Biomass Project if a diesel chipping operation is installed.

1050 HP Diesel Fired Engine for the wood chipping unit (WC03) is a new limited use (limited to 3000 hrs of operation per twelve consecutive months) stationary RICE (compression ignition) with a rating of more than 500 HP and located at a major source of HAP emissions. It does not have to meet the requirements of Subpart ZZZZ and Subpart A except for the initial notification requirements of § 63.6645(h) [40 CFR 63.6590(b)(1)(i)]. It is not required to add this initial notification requirement in the permit as it is already satisfied via the permit application.

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 biomass-fired steam generating unit associated with the proposed project are most likely to occur during 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.

Four 100 mmBtu/hr oil fired igniters will be installed to facilitate startup of the steam generating unit for biomass operation (one in each corner, approximately 13 ft above the grate). Initially, the oil igniters will be fired without any biomass being injected into the steam generating unit. Heat input will initially be at about 24 mmBtu/hr total for these igniters, ramping up in steps to their maximum rating of 400 mmBtu/hr. These igniters are sized to bring the steam generating unit up to 30 percent of the steam generating unit full load rating. This amount of heat input is sufficient to achieve the operating temperature of the superheater and turbine. The amount of time necessary for the oil igniters to achieve the desired steam generating unit temperature is approximately twelve hours.

Once stable steam generating unit conditions are reached, biomass will begin to be injected. This is done by seeding the grate surface to slowly start grate ignition at minimum undergrate airflow. Biomass injection flow is increased over a three-hour period to the point where the combination of heat input from the biomass and oil igniters totals about 828 mmBtu/hr while maintaining the maximum heat input from the oil burners. This is the heat input necessary for minimum steady-state load. Over the next two hours biomass fuel input to the steam generating unit is increased and oil firing is proportionally decreased on a heat input basis until the steam generating unit is firing on 100 percent biomass at the minimum steady-state load heat input. This ends the startup process, which takes about seventeen hours total for a cold start.

A warm startup is very similar to a cold startup except that the amount of time necessary to fire the oil igniters and achieve that target steam generating unit temperature is reduced. For a typical warm start, this initial steam generating unit heating may take about eight hours. At that point the remainder of the warm startup process is the same as described for the cold startup above. A typical warm startup could take about thirteen hours.

Table 3-1 shows the worst-case emission rates during startup for the oil ignitors and biomass and compares the maximum hourly mass emission rates during startup with the steady-state rates. Note that during the startup process the multiclones and the ESP are both operating to reduce PM_{10} emissions.

Table 3-1 Startup vs. Steady-State Emissions Comparison

	Worst Case Rates (lb/mmBtu)				Worst Case Hourly Mass Emissions (lb/hr)				
	Oil	Biomass			Oil	Biomass	Combined	Biomass Only	
Pollutants	Startup*	Startup*	Steady-State Min Load	Steady-State Full Load	Startup*	Startup*	Total	Steady-State Min Load	Steady-State Full Load
SO_2	0.001	0.66	0.66	0.66	0.4	255.5	255.9	546.5	867.9
NOx	0.18	0.3	0.23	0.25	72.0	116.1	188.1	190.4	328.8
CO	0.037	0.45	0.45	0.45	14.8	174.2	189.0	372.6	591.8
VOC	0.005	0.05	0.05	0.05	2.0	19.4	21.4	41.4	65.8
PM/PM_{10}	0.05	0.04	0.04	0.04	20.0	15.5	35.5	33.1	52.6

*During startup, biomass is 70% of load and oil is 30% of load.

The result of this comparison is that the hourly mass rates for all pollutants during startup are lower than the highest steady-state mass rates. Thus, the full load mass rates are the basis for calculating the maximum annual emissions (PTE), and this is a conservative approach. Also, this shows that for the PSD pollutant (CO) with short-term ambient standards (1-hour and 8-hour), the steady-state hourly mass rates are so much higher than maximum hourly rate during startup (by a factor of at least two) that air quality modeling using steady-state emissions should be sufficient to determine the worst-case impacts.

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.

Therefore, this applicability evaluation only addresses the biomass-fired steam-generating unit (Source Code: SG03)**,** which employs a new MultiClone (Source Code: MC03) and an existing Dry ESP (Source Code: EP03) to control PM_{10}. The CAM plan for the biomass-fired steam generating unit (Source Code: SG03) for PM_{10} will be developed after startup of the converted biomass unit. Based on this analysis, Plant Mitchell will submit a CAM Plan that describes the general and performance criteria for the required number of performance indicators.

Federal Rule – 40 CFR 68 – Chemical Accident Prevention Provisions

Part 68, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR Part 68) Chemical Accident Prevention Provisions
This regulation establishes the list of regulated substances and thresholds, the petition process for adding or deleting substances to the list of regulated substances, the requirements for owners or operators of stationary sources concerning the prevention of accidental releases, and the State accidental release prevention programs approved under section 112(r). The list of substances, threshold quantities, and accident prevention regulations promulgated under 40 CFR Part 68 do not limit in any way the general duty provisions under section 112(r)(1) [40 CFR 68.1].

An owner or operator of a stationary source that has more than a threshold quantity of a regulated substance in a process, as determined under §68.115, must comply with the requirements of this part no later than the date on which a regulated substance is first present above a threshold quantity in a process [40 CFR 68.1(a)(3)]. Process means any activity involving a regulated substance including any use, storage, manufacturing, handling, or on-site movement of such substances, or combination of these activities. For the purposes of this definition, any group of vessels that are interconnected, or separate vessels that are located such that a regulated substance could be involved in a potential release, shall be considered a single process [40 CFR 68.3].

Facilities subject to the rule must conduct a hazard assessment, compile a 5-year accident history, develop an accident prevention program, develop an emergency response program, and submit risk management information to EPA as specified in the regulation. However, the existing facility is not subject to RMP requirements and does not expect that the proposed project will change this status.

Federal Rule – 40 CFR 70 – Title V Operating Permit

Part 70, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR Part 70) State Operating Permit Programs [Title V]
The regulations in 40 CFR Part 70 provide for the establishment of comprehensive State air quality permitting systems consistent with the requirements of Title V of the Clean Air Act (Act) (42 U.S.C. 7401, *et seq.*). These regulations define the minimum elements required by the Clean Air Act for State operating permit programs and the corresponding standards and procedures by which the Administrator will approve, oversee, and withdraw approval of State operating permit programs. Georgia has established such a program. Plant Mitchell, because it can potentially emit applicable pollutants above

the applicable major source thresholds, is subject to 40 CFR Part 70. All sources subject to these regulations must have a permit to operate that assures compliance by the source with all applicable requirements [40 CFR 70.1(b)]. An application to modify this permit to include the proposed facility expansion is in Appendix B of this preliminary determination.

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

As noted in the initial Title V narrative for Title V Permit No. 4911-095-0002-V-01-0, this facility is subject to the requirements in Title IV of the Clean Air Act. They are subject to 40 CFR 72 (permits), 73 (sulfur dioxide), 75 (monitoring), and 76 (nitrogen oxides). The only affected unit at Plant Mitchell is Unit 3.

40 CFR 72.50(a)(1) allows a complete Phase II Permit Application to be attached to the Title V Permit as part of the Permit. The Phase II Acid Rain Permit emission limits took effect on January 1, 2000 and was revised with Application No. TV-14897 dated December 4, 2003. Phase II Acid Rain requirements were also updated with the Title V Permit Amendment No. 4911-095-0002-V-02-2. The current Acid Rain Permit will expire on December 31, 2013. The facility should submit a Phase II permit renewal application at least six (6) months prior to the expiration date of the Phase II Acid Rain Permit. Pursuant to 40 CFR Part 72, Subpart G, Section 72.73(b)(2), Phase II Acid Rain Permits expire five (5) years after the effective date of the original permit.

For further information on the facility's background with meeting the requirements of the Acid Rain Program, please refer to the narrative for the initial Title V Permit No. 4911-095-0002-V-01-0.

Federal Rules – Clean Air Interstate Rule (CAIR)

The Clean Air Interstate Rule regulations specified in Federal Rule 40 CFR 96 apply to the proposed simple-cycle electric generating unit because it has a nameplate capacity greater than 25 MW, it is fossil-fuel fired, and it will supply electricity for sale, whether wholesale or retail.

Part 96, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR Part 96) Subpart AA – Clean Air Interstate Rule [CAIR] NOx Trading Program General Provisions, Subpart BB – CAIR Designated Representative for CAIR NOx Sources, Subpart CC – Permits, Subpart FF – CAIR NOx Allowance Tracking System, Subpart GG – CAIR NOx Allowance Transfers, Subpart HH – Monitoring and Reporting

And:

Part 96, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR Part 96) Subpart AAA – Clean Air Interstate Rule [CAIR] SO_2 Trading Program General Provisions, Subpart BBB – CAIR Designated Representative for CAIR SO_2 Sources, Subpart CCC – Permits, Subpart FFF – CAIR SO_2 Allowance Tracking System, Subpart GGG – CAIR SO_2 Allowance Transfers, Subpart HHH – Monitoring and Reporting

These regulations established the model rule comprising general provisions and the designated representative, permitting, allowance, monitoring, and opt-in provisions for the State Clean Air Interstate Rule (CAIR) NOx and SO_2 Trading Programs, under section 110 of the Clean Air Act, §51.123 and §51.124 of Chapter I, as a means of mitigating interstate transport of fine particulates, NOx and sulfur dioxide. The owner or operator of a unit or a source was to comply with the requirements of these regulations as a matter of federal law only if the State with jurisdiction over the unit and the source incorporated by reference such subparts or otherwise adopts the requirements of such subparts in accordance with §51.123(o)(1) or (2) and §51.124(o)(1) or (2) of Chapter I, the State submitted to the Administrator one or more revisions of the State implementation plan that include such adoption, and the Administrator approved such revisions.

On December 23, 2008, the U.S. Court of Appeals for the District of Columbia Circuit reinstated the CAIR rule. The court remanded the case without vacatur of CAIR for EPA to conduct further proceedings consistent with the July 11, 2008 opinion in this case, in which EPA was directed to correct identified flaws with this rule. Therefore, this regulation is applicable to the proposed steam generating unit (Source Code: SG03) when it commences operation after the modification, because it will fire fuel oil as startup fuel.

Updated CAIR requirements were incorporated into Permit Amendment No. 4911-095-0002-V-02-4 issued on November 16, 2009 for the existing coal fired steam generating unit (Source Code: SG03).

4.0 CONTROL TECHNOLOGY REVIEW

The proposed project will result in emissions that are significant enough to trigger PSD review for the following pollutants: $PM_{2.5}$, PM_{10}, CO and VOC.

SG03 Biomass Steam Generating Unit - Background

The biomass steam generating unit (Source Code SG03) is a biomass-fired stoker boiler and will require a new fuel handling, processing, storage, and delivery system. The steam generating unit will be converted from a coal-fired steam generating unit. The conversion will be accomplished by replacing the bottom section of the existing steam generating unit and installing a stoker along with other pressure parts and back end equipment modifications. This conversion will also include adding a cyclone separator ("multiclone") ash removal system upstream of an existing air preheater, modifying the bottom ash removal system, and replacing the coal yard and coal handling system with a new biomass yard and biomass delivery system.

SG03 – PM/PM_{10} Emissions

Applicant's Proposal

Step 1: Identify All Control Technologies

The emissions control technologies for filterable PM_{10} gas emissions from a stoker biomass-fired steam generating unit include the following:

- Wet ESPs (Electrostatic Precipitator)
- Pulse Energization
- COHPAC (Compact Hybrid Particulate Collector)
- Particle Agglomerator
- Gas Flow Optimization
- Juice Can Power Conditioning
- Moisture Injection
- Increase Plate Area
- Increase Electrical Sectionalization
- Add Extra Collection Field
- High Frequency Power Supplies
- Mechanical Collector
- Digital ESP Controls
- Carbon Reentrainment Reduction
- Wet Flue Gas Desulfurization

In determining this initial list of appropriate control technologies, Georgia Power considered all field-proven, commercially available upgrade options listed in the EPRI ESP upgrade guidelines manual.[1] These technologies have been applied at multiple plants and the suppliers may provide performance guarantees. Two additional technologies are included because they have reached some degree of maturity in the period of time since the original guidelines documents were prepared: the Indigo Technologies' particle agglomerator and the GE/BHA "Juice Can" power conditioner.

See Section 4.3.3 of the application, for additional information on these control technologies.

[1] *Guideline for Upgrading Electrostatic Precipitators:Volume 2*, EPRI Report Number TR-113582

Step 2: Eliminate technically infeasible options

Wet ESP

WESP is considered a technically feasible option for Unit 3. The unit could be retrofitted with a WESP to reduce filterable particulate matter as well as sulfuric acid emissions. Georgia Power expects sulfuric acid removal to be low because of the relatively low sulfur content of the fuel. The WESP would be installed downstream of the existing ESP in a grade-mounted, horizontal flow configuration. For purposes of this analysis, Georgia Power has assumed that the WESP design would incorporate three fields in the direction of gas flow. This is likely to be a very expensive option for Mitchell 3 because it will require the construction of a new stack and a water treatment system.

Pulse Energization

Pulse energization is a technology that is useful for increasing the ESP collection efficiency for high resistivity fly ash particles. However, high resistivity is not an issue for Unit 3. Georgia Power expects low to moderate levels of ash resistivity, particularly during the combustion of certain wood blends that produce a high concentration of unburned carbon. As a result, pulse energization is not considered a technically feasible option for this unit because it is not expected to result in any PM_{10} removal.

COHPAC

COHPAC is available in two configurations: COHPAC I and COHPAC II. COHPAC I requires the installation of a fabric filter in a separate casing downstream of the existing ESP. COHPAC II is a retrofit of the outlet field of an existing ESP with a fabric filter. Of the two configurations, only COHPAC I is commercially available and therefore COPHAC II is technically infeasible.

COHPAC I is considered a technically feasible option for Unit 3. However, this will likely be an expensive retrofit for this unit because the Forced Draft (FD) and/or Induced Draft (ID) fans will need to be replaced to account for the additional pressure drop across the baghouse. In addition, because of the potential for relatively high operating temperatures, this application will require the installation of expensive, heat-resistant fabrics.

Particle Agglomerator

The particle agglomerator is not considered a technically feasible option for Unit 3. This technology has not been proven on biomass-fired sources or coal-fired installations. The results have been mixed. Furthermore, this technology is not proven for flue gas streams containing high levels of unburned carbon, such as those that might be experienced when burning certain wood fuel blends.

Gas Flow Optimization

Gas flow optimization is not considered a technical feasible option for Unit 3. Georgia Power has already conducted gas flow improvements and considers the existing flow distribution to be optimized.

Juice Can Power Conditioning

Juice Can Power Conditioning technology is not considered a technically feasible option for Unit 3. Modeling of the ESP operation during baseline conditions suggests that there is a relatively high current density with little or no sparking on the inlet fields. It is expected that Juice Cans would not provide much benefit under these operating conditions.

Moisture Injection (for PM_{10} and/or SO_3 control)

Field experience with moisture conditioning/flue gas humidification has shown this to be an infeasible technology due to the associated maintenance problems. Moisture injection has repeatedly been shown to cause heavy deposits of sludge in the ductwork.

Increase Plate Area

Increasing the plate height is not considered a technically feasible option for this unit. The Unit 3 ESP has an aspect ratio of approximately 1.1, which is already well below conventional design specifications (1.5+) for a new high-efficiency ESP.

Increase Electrical Sectionalization

Splitting collection fields is not considered a technically feasible option for this unit. The Unit 3 ESP collection fields were already split as part of the ESP modifications conducted in 1999, resulting in eight electrical fields in the direction of gas flow. Georgia Power anticipates only negligible performance benefit from further sectionalization of the ESP.

Add Extra Collecting Field

Adding collection surface to any ESP will improve performance, although the benefit significantly decreases when the number of fields exceeds typical design specifications. This option is not considered a technically feasible option for Unit 3 because the ESP is equipped with eight electrical fields in the direction of gas flow, which is already well designed for a high performance ESP. Georgia Power anticipates only negligible performance benefit from adding more collecting fields.

High Frequency Power Supplies

Retrofit of the existing, transformer/rectifier sets (TR-sets) with new, high frequency power supplies is considered a technically feasible upgrade option for the Unit 3 ESP. High frequency power supplies are normally added to one or more inlet fields, where they can provide the most benefit due to the relatively high space charge. For this application, Georgia Power has included an evaluation of high frequency power supplies on the first and second inlet fields (Field #1, #2).

Mechanical Collector

Installation of a mechanical collector is considered a technically feasible upgrade option for the Unit 3 ESP. Georgia Power is already planning to add two multiclone collectors upstream of the ESP as part of the steam generating unit conversion project in order to protect the air preheater. The purpose of the multiclones is to reduce unburned carbon concentration, which will reduce the potential for air heater damage and improve ESP performance. The effects of the multiclones have been included as part of baseline operating scenario.

New ESP Controls

New ESP Controls are not considered a technically feasible upgrade option. The Unit 3 is already equipped with GE/BHA SQ-300 controls, which represents the latest generation of ESP control technology.

Carbon Reentrainment Reduction

For the baseline fuel operating scenario, projected levels of unburned carbon in the flue gas are relatively low, which suggests low carbon reentrainment losses in the ESP. While future operation of the unit may include fuel blends that result in high levels of unburned carbon, it is impossible at this time for Georgia Power to estimate with any reasonable certainty the reduction in reentrainment losses that could be achieved by modifying gas flow or installing additional hopper baffles. Such an evaluation would first require a quantification of carbon losses and a detailed study to identify potential ESP modifications. For these reasons, Georgia Power does not consider this option to be feasible at this time.

Lime Injection (with COHPAC or WESP)

Sorbent injection for SO_3 control is considered a technically feasible option for Unit 3 for the reduction of condensable PM_{10} emissions, although removal rates will be low because of the extremely low sulfur concentration in the fuel. While there are a variety of injection options and sorbent types, for the purpose of this analysis, Georgia Power has considered lime injection due to the relatively low cost and high performance of the sorbent. However, while lime injection can provide significant reduction in flue gas SO_3 concentration, it produces collateral filterable PM_{10} emissions due to the added particulate. In addition, since lime is typically injected upstream of the ESP, it can create a reduction in ESP performance due to the increased loading and adverse changes in flue gas properties. Because of these issues, Georgia Power has assumed the sorbent would be injected downstream of the ESP, requiring either a WESP or COHPAC.

Summary of Feasible Upgrade Options

Table 4-1 summarizes the feasible PM_{10} control options for Unit 3. All other options are considered technically infeasible and have been excluded from the remainder of the PM_{10} BACT determination analysis.

Table 4-1 Technically Feasible PM_{10} Control Options for Mitchell 3

Description
High Frequency Power Supply (Field #1 and Field #2)
High Frequency Power Supply (Field #1)
COHPAC I
WESP
COHPAC I & Lime Injection
WESP & Lime Injection

Step 3: Ranking of Available Control Techniques

The evaluation of the various PM_{10} control options requires a comparison of total PM_{10} (filterable and condensable) reduction of each option. Section 4.3.5, *Control Effectiveness of Feasible Options*, of the application describes in detail the evaluation process performed by Georgia Power and summarizes the assumptions used to determine the control effectiveness and the expected emissions reduction of each feasible option.

Table 4-2 summarizes the control effectiveness of the various control options.

Table 4-2 Control Effectiveness of Upgrade Options

Option	Description	Filterable PM_{10} [tpy]	Condensable PM_{10} [tpy]	Total PM_{10} [tpy]	Overall Collection Efficiency [%]
1	COHPAC I with Lime Injection	14	111	125	57%
2	WESP	17	112	129	56%
3	COHPAC I	14	116	130	55%
4	WESP with Lime Injection	22	111	132	54%
5	High Frequency Power Supply (Field #1, #2)	116	116	233	20%
6	High Frequency Power Supply (Field #1)	137	116	253	13%
Baseline (firing 100% tops and limbs)		174	116	291	

The control efficiencies referenced in Section 4.3.5 of the facility's application are for certain fractions of total PM_{10}. The total PM_{10} estimate is comprised of three parts: filterable PM_{10}, sulfuric acid mist (one part of condensable PM_{10}), and other condensables. The control efficiencies in Section 4.3.5 of the application are specifically either for filterable or sulfuric acid mist PM_{10}. No reduction is assumed for other condensables (this is consistent with AP-42, which states that controls do not appear to have an effect on condensables emission factors). The overall control efficiencies as listed in Table 4-2 calculate the effect on total PM_{10}, accounting for the fact that the other condensables are not reduced by the controls.

Step 4: Most Effective Control

The data in Table 4-2 show that COHPAC with lime injection provides the highest overall collection efficiency (57%). For further details refer to the "*PM Control Effectiveness Summary*" in Section 4.3.5 of the application.

Refer to Section 4.3.6 "*Impacts Analysis of Feasible Options*" for the following impacts

- Energy impacts of the WESP and COHPAC control technologies.
- Environmental Impacts
- Economic Impacts

Economic Impacts

Total Capital Costs

Section 4.3.6 of the application discusses the total capital costs or total capital investment (TCI) associated with each of the control options, including direct and indirect costs.

Direct Capital Costs

For the specific details for the direct capital costs for High Frequency Power Supplies, COHPAC, WESP and Lime Injection, please refer to section 4.3.6 of the application.

Indirect Capital Costs

For the specific details for the indirect capital costs for High Frequency Power Supplies, please refer to section 4.3.6 of the application. A breakdown of these costs are summarized in Table 4-3.

Table 4-3 Breakdown of Indirect Capital Costs

Indirect Cost Component	Factor	
Engineering (in-house)	10%	Equipment Cost
Construction and Field Expenses (in-house)	5%	Equipment Cost
Contractor Fees	10%	Equipment Cost
Contingency Cost (small capital projects)	15%	TDC*
Contingency Cost (large capital projects)	15%	TDC*
Lost Interest During Construction (large capital projects)	7.1%	TDC*

*Total direct capital costs

Capital Cost Summary

The total capital investment (TCI) represents the combination of total direct and indirect capital costs associated with each control option. Refer to section 4.3.6 of the application for details of the total capital cost estimates for each control option. Table 4-4 shows the total capital cost estimates for each control option.

Table 4-4 Breakdown of Total Capital Investment

Option	Description	TCI [$]
1	COHPAC I with Lime Injection	$44,500,000
2	WESP	$40,000,000
3	COHPAC I	$43,000,000
4	WESP with Lime Injection	$41,500,000
5	High Frequency Power Supply (Field #1, #2)	$190,000
6	High Frequency Power Supply (Field #1)	$100,000

Annualized Costs

Refer to section 4.3.6 of the application for the breakdown of the following **annualized** costs:

- Direct Operating Costs
- Indirect Operating Costs
- Capacity and Energy Penalties

Annualized Cost Summary

A breakdown of the total, annualized costs (in 2008 dollars) associated with each control option is provided in Table 4-5.

Table 4-5 Annualized Control Cost Summary (2008 Dollars)

Option	Description	Direct Operating Costs [$]	Indirect Operating Costs[$]	Capital Recovery Cost of Additional Capacity [$]	Cost of Makeup Energy [$]	Total Annualized Cost [$]
1	COHPAC I with Lime Injection	$1,630,000	$5,883,500	$57,500	$496,000	**$8,070,000**
2	WESP	$411,000	$5,226,200	$25,400	$219,000	**$5,880,000**
3	COHPAC I	$1,280,000	$5,689,200	$57,500	$496,000	**$7,520,000**
4	WESP with Lime Injection	$762,000	$5,428,400	$25,400	$219,000	**$6,430,000**
5	High Frequency Power Supply (Field #1, #2)	0	$24,900	n/a	n/a	**$25,000**
6	High Frequency Power Supply (Field #1)	0	$13,100	n/a	n/a	**$13,100**

Refer to section 4.3.6 of the application for other cost factors not included in the economic analysis, and the details of the economic analysis performed. This section discusses average cost effectiveness, and incremental cost effectiveness of the control options.

Economic Analysis

Georgia Power performed the cost analysis of the various control options in accordance with EPA's BACT Guidelines and the *EPA Air Pollution Control Cost Manual*.

Average Cost Effectiveness

Average cost effectiveness refers to the total annualized costs of a control option, in dollars per year, divided by the estimated annual emissions reduction associated with the control option, in tons per year. Average cost effectiveness is expressed in terms of (annualized) dollars per ton of pollutant removed ($/ton). Table 4-6 summarizes the average cost effectiveness of each upgrade option. Georgia Power considers Option #5 and #6 (high frequency power supplies) to be the only cost effective options listed above based on average cost effectiveness.

Table 4-6 Average Cost Effectiveness of Control Options

Option	Description	Annualized Cost [$/yr]	PM_{10} Reduction [tpy]	Average Cost [$/ton]
1	COHPAC I with Lime Injection	$8,070,000	161	$50,000
2	WESP	$5,880,000	158	$37,300
3	COHPAC I	$7,520,000	160	$46,900
4	WESP with Lime Injection	$6,430,000	156	$41,300
5	High Frequency Power Supply (Field #1, #2)	$25,000	58	$431
6	High Frequency Power Supply (Field #1)	$13,100	38	$348

Incremental Cost Effectiveness

Incremental cost effectiveness (ICE) is used to compare the cost and performance of a particular upgrade option to the next most stringent upgrade option. Dominant control alternatives can be identified by graphing the average cost effectiveness of each upgrade option. The general relationship in average cost effectiveness between dominant control options will form a smooth, non-linear curve known as the "least-cost envelope". Control options that lie outside of the least-cost envelope are considered inferior options because the cost per ton of particulate removed is inconsistent with other competing alternatives.

Georgia Power calculated the incremental cost effectiveness of the dominant control options, as shown in Table 4-7, sorted in ascending order by annualized cost.

Table 4-7 Incremental Cost Effectiveness of Dominant Upgrade Options

Option	Upgrade Option	Average Cost [$/ton]	Incremental Cost [$/ton]
1	COHPAC I with Lime Injection	$50,000	$569,000
2	WESP	$37,300	$58,700
5	High Frequency Power Supplies (Field #1, #2)	$431	$587
6	High Frequency Power Supplies (Field #1)	$348	NA

Cost Analysis Summary

The cost analysis suggests that Option #3 (COHPAC) and Option #4 (WESP with lime injection) should be eliminated from further consideration. These options were identified as inferior because they fall inside the least-cost envelope. Of the remaining dominant upgrade options, Option #1 (COHPAC I with Lime Injection) and Option #2 (WESP) were eliminated due to excessive average and incremental costs. The next most stringent upgrade option, Option #5 (High Frequency Power Supplies in Field #1, #2) is the most cost-effective upgrade option. Average cost and incremental costs for this option are considered reasonable.

Step 5: Selection of BACT

BACT for PM_{10} has been determined to be installation of the multiclones and upgrading the existing ESP to install new high frequency power supplies on the first two fields (Field #1 and Field #2) of the eight total fields. This choice was based on a review of all available PM_{10} controls and considering the energy, environmental, and economic impacts of the feasible controls. From this analysis and a review of the EPA RBLC and other sources of information, it is clear that a PM_{10} emissions limit of 0.04 lb/mmBtu on a short-term average basis is the appropriate PM_{10} BACT limit for this project.

Table 4-8 includes a summary of the control technologies under consideration, including the relevant factors in making the PM_{10} BACT determination, ranked in descending order according to the estimated emissions reduction of each option and the suggested PM_{10} BACT limit.

Table 4-8 Summary of Top-Down BACT Impact Analysis Results for PM_{10} for Unit SG03

		PM_{10} Emissions		Economic Impacts				Energy Impacts	Environmental Impacts
Option	Description	Post-Retrofit Emissions [tpy]	Emissions Reduction [tpy]	Installed Capital Cost [$]	Total Annualized Cost [$/yr]	Average Cost Effectiveness [$/ton]	Incremental Cost Effectiveness [$/ton]	Incremental Increase over Baseline (kW)	Adverse Environmental Impact [Yes/No]
1	COHPAC I with Lime Injection	125	166	$44,500,000	$8,070,000	$50,000	$569,000	1,130	Yes
2	WESP	129	161	$40,000,000	$5,880,000	$37,300	$58,700	500	Yes
5	High Frequency Power Supply (Field #1, #2)	233	58	$190,000	$25,000	$431	$587		No
6	High Frequency Power Supply (Field #1)	253	38	$100,000	$13,100	$348	NA		No

EPD Review – PM_{10} Control

In addition to reviewing the permit application and supporting documentation, the Division has performed independent research of the PM_{10} BACT analysis and used the following resources and information:

- USEPA RACT/BACT/LAER Clearinghouse[2]
- Final/Draft Permits and Final/Preliminary Determinations for similar biomass project permits such as Multitrade, Yellow Pine, and Plant Carl
- Title V Operating Permit for BioEnergy, LLC, West Hopkinton, NH, September 12, 1995, the Addendum dated March 3, 1997 and modification dated June 21, 2002
- Title V Operating Permit for Whitefield Power and Light Company, NH, January 11, 1999, the Amendment dated November 15, 1999, April 12, 2000, June 26, 2001 and November 15, 2001
- NSR Narrative and Permit No. 3434, Western Water and Power Production LLC, Estancia Basin Biomass Power Generation Plant, Albuquerque, NM, March 29, 2007
- Massachusetts Division of Energy Resources, Renewable Energy Portfolio Standard, Statement of Qualification, Schiller Station Unit 5, December 1, 2006
- Minnesota Pollution Control Agency, Air Quality Division, Toni Volkmeier
- Minnesota Pollution Control Agency, Air Quality Division, Technical Support Document and Air Emission Permit No. 01700002-012, Sappi Cloquet LLC, Cloquet, MN, 10/28/2009
- Biomass Group, LLC, South Point Power, Final Permit to Install Modification, South Point, Lawrence County, Ohio, issued 4/4/2006
- Biomass Group, LLC, South Point Power, Permit to Install Application, Particulate Matter and Carbon Monoxides BACT Analysis, South Point, Lawrence County, Ohio, Revision 5, 9/23/04
- Biomass Group, LLC, South Point Power, Request for Proposal, South Point, Lawrence County, Ohio, 10/15/2003

The Division has prepared BACT comparison spreadsheets for all pollutants for the similar units using the above-mentioned resources and they are attached in Appendix D.

GA Power proposed a total PM_{10} BACT limit of 0.04 lb/mmBtu on a three-hour average and provided justification on page 4-42 of the application. The proposed value is post controls emissions considering the installation of a mutliclone mechanical collector system and high frequency power supplies on two fields of the ESP. The Division asked the permit applicant to provide more justification and references in support of the limit. GA Power provided the following justification:

GA Power states that the Mitchell biomass conversion is a unique project for which valid comparisons with other facilities cannot always be made. GA Power believes that the limit proposed is reasonable and suitable for this specific project.

GA Power states that the Mitchell Project is unique for the following reasons:

- *Mitchell is an existing, currently operating source*:
  - This project seeks to continue to use as much of the existing infrastructure as possible after the conversion, including most of the steam generating unit, the electrostatic precipitator, existing substations and transmission, etc. Doing so enables the project to be much more cost effective, but also includes conservation benefits by reducing the amount of resources consumed by the project (e.g. steel, concrete, land disturbance, etc.). The steam generating unit itself will remain largely intact, with only the bottom replaced with a stoker grate. The project is, in essence, a retrofit. Retrofit projects involve marrying equipment of different vintages and designs. Design flexibility is far more limited in a

[2] http://cfpub1.epa.gov/rblc/htm/bl02.cfm

retrofit when compared to a new facility. As a result, the performance of retrofit projects is generally less predictable than facilities designed and built brand new. In light of this, GA Power has also modeled emissions performance specifically for the Mitchell Steam Generating Unit and other equipment, taking into account various specifications, such as size, temperatures, flows, etc. for the PSD application.

- *Mitchell SG03 will be one of the largest conversions of an existing Steam Generating Unit to a stoker grate:*
    - To GA Power's knowledge, a conversion of this scale has not yet been attempted. Other facilities may be planning to do similar conversions in the near future, but there are currently no other 96 megawatt-net biomass steam generating units that can compare to this project. Performance demonstrated by smaller steam generating units cannot always be achieved at larger scales.

- *Mitchell must maintain biomass fuel flexibility:*
    - Biomass fuels, in general, are more variable in nature than coal. Moisture content, ash content, and other characteristics can vary greatly. For the Mitchell application, GA Power has modeled four categories of biomass fuel types. For each emission limit, GA Power has used the worst case fuel type for modeling the expected emissions performance.

In an information package received on May 24, 2009, located in Appendix B, GA Power also provided justification for the use of condensables and filterable emission factors of 0.02 lb/mmBtu each.

<u>Conclusion – PM_{10} Control</u>

After a review of available controls for PM_{10} (i.e. Wet ESP, Pulse Energization, COHPAC, Particle Agglomerator, Gas Flow Optimization, Juice Can Power Conditioning, Moisture Injection, Increase Plate Area, Increase Electrical Sectionalization, Add Extra Collection Field, High Frequency Power supplies, Mechanical Collector, Digital ESP Controls, and Carbon Reentrainment Reduction, the BACT selection for the SG03 is summarized below in Table 4-10.

Table 4-10: BACT Summary for Unit SG03

Pollutant	**Control Technology**	**Proposed BACT Limit**	**Averaging Time**	**Compliance Determination Method**
PM_{10}	High Frequency Power Supply (Field #1, #2) Multiclone Mechanical Collector System	0.04 lb/mmBtu	3 hour average	Method 5, Method 202 (Initial and Annual Testing)

SG03 – Particulate Matter Less than 2.5 Microns ($PM_{2.5}$) Emissions

Background

EPA policy, as expressed in its 1997 and 2005 $PM_{2.5}$ policy memoranda and in its recent NSR final rule allows sources located in attainment areas to continue to use PM_{10} as a surrogate for $PM_{2.5}$. In light of recent changes in EPA policy, Georgia Power provided the following additional information regarding fine particulate matter emissions or "$PM_{2.5}$", to supplement its permit application for the proposed Plant Mitchell biomass conversion.

Georgia Power believes that PM_{10} is a reasonable surrogate for ensuring compliance with the Clean Air act requirements for $PM_{2.5}$, as contemplated under EPA's PM_{10} Surrogate Policy. However, rather than proceeding on a general presumption that PM_{10} is always a reasonable surrogate for $PM_{2.5}$, the discussion below in this section demonstrates that PM_{10} is a reasonable surrogate for $PM_{2.5}$ under the specific facts and circumstances of the proposed Plant Mitchell biomass conversion.

EPA's PM_{10} Surrogate Policy was first announced on October 23, 1997 in a memorandum from John S. Seitz regarding implementation of the 1997 $PM_{2.5}$ standards, entitled "*Interim Implementation for the New Source Review Requirements for $PM_{2.5}$*". The Seitz Memorandum explained that sources could use implementation of a PM_{10} program as a surrogate to meet the $PM_{2.5}$ NSR requirements until certain technical difficulties were resolved. On April 5, 2005, EPA issued a second guidance memorandum from Stephen D. Page entitled "*Implementation of New Source Review Requirements in $PM_{2.5}$ Nonattainment Areas*" which re-affirmed the Surrogate Policy announced in the Seitz memorandum. The Surrogate policy was again endorsed on May 16, 2008 in the context of EPA's final rule for the "*Implementation of the New Source Review (NSR) Program for Particulate Matter Less than 2.5 Micrometers ($PM_{2.5}$)*", 96 Fed. Reg. 28,321. In the preamble to that final rule, EPA set forth its transition policy for the $PM_{2.5}$ NSR requirements, stating that, if a SIP-approved state is unable to implement a PSD program for $PM_{2.5}$ under existing state regulations, the state may continue to implement a PM_{10} program under the Surrogate Policy originally announced in the Seitz Memorandum.

However, in the context of a recent challenge to the permit for a new unit at the Louisville Gas and Electric Co. Trimble County Generating Station, EPA changed the way it applies its Surrogate Policy.[3] In that decision, Administrator Jackson granted a petition to object to the permit on the grounds that Louisville Gas and Electric had relied solely on EPA's PM_{10} Surrogate Policy without conducting further analysis into whether PM_{10} was a reasonable surrogate for $PM_{2.5}$ in the context of the specific permit and facility in question. Therefore, under the reasoning of the Trimble County decision, it may now be appropriate to include additional analysis confirming that PM_{10} is a reasonable surrogate for $PM_{2.5}$ to support the use of EPA's Surrogate Policy in the context of the Plant Mitchell biomass conversion.

Applicant's Proposal

In its PM_{10} BACT determination for the Plant Mitchell biomass conversion, Georgia Power evaluated all available PM control technologies, including those later determined to be technically infeasible. Each of the available control options reviewed would be capable of removing both PM_{10} and $PM_{2.5}$, and there are no additional $PM_{2.5}$ pollution control technologies available that Georgia Power did not consider during its PM_{10} BACT analysis. After identifying all the available control options, Georgia Power eliminated those options that would be technically infeasible for the project. The control options that were eliminated as technically infeasible for PM_{10} would still be infeasible regardless of which fraction of PM

[3] In a footnote, EPA recognized that its Trimble County decision differed somewhat from a previous decision issued on August 30, 2007 due to "an evolving understanding of the technical and legal issues associated with the use of the PM_{10} Surrogate Policy."

is considered. Therefore, the list of technically feasible controls that Georgia Power prepared during its PM_{10} BACT determination would be the same for $PM_{2.5}$.

To complete its PM_{10} BACT determination for the biomass conversion, Georgia Power reviewed the cost-effectiveness of the feasible control options and selected the high-frequency power supplies as PM_{10} BACT because all of the other control options were not cost-effective, as shown in the abbreviated Table 4-9 on p. 26, below:

	PM_{10} Emissions		Economic Impacts			
Description	Post-Retrofit Emissions [tpy]	Emissions Reduction [tpy]	Installed Capital Cost [$]	Total Annualized Cost [$/yr]	Average Cost Effectiveness [$/ton]	Incremental Cost Effectiveness [$/ton]
COHPAC I with Lime Injection	125	166	$44,500,000	$8,070,000	$50,000	$569,000
WESP	129	161	$40,000,000	$5,880,000	$37,300	$58,700
High Frequency Power Supply (Field #1, #2)	233	58	$190,000	$25,000	$431	$587
High Frequency Power Supply (Field #1)	253	38	$100,000	$13,100	$348	NA

Just as the technical feasibility of the various control options would not change depending on which fraction of PM is considered, neither would the total cost of installing and operating each individual control option. However, the cost-*effectiveness* of the control options (in $/ton) would differ for $PM_{2.5}$ because fewer tons of $PM_{2.5}$ will be captured by the controls for two reasons. First, $PM_{2.5}$ only represents a subset of PM_{10}. As such, there will not be as many tons of $PM_{2.5}$ for the controls to capture, even at the PM removal efficiencies assumed in the table above. Second, the control technologies are also generally less effective at controlling $PM_{2.5}$ than PM_{10} because $PM_{2.5}$ is more difficult to capture. For these reasons, each control option will actually be *less* cost-effective for $PM_{2.5}$ than for PM_{10} because the calculations will necessarily assume lower emission reductions for the same cost. The following table compares the cost-effectiveness of the available and feasible $PM_{2.5}$ control options:

	$PM_{2.5}$ Emissions		Economic Impacts			
Description	Post-Retrofit Emissions [tpy]	Emissions Reduction [tpy]	Installed Capital Cost	Total Annualized Cost [$/yr]	Average Cost Effectiveness [$/ton]	Incremental Cost Effectiveness [$/ton]
COHPAC I with Lime Injection	115	76	$44,500,000	$8,070,000	$106,000	$168,400
WESP	128	63	$40,000,000	$5,880,000	$93,300	$130,000
High Frequency Power Supply (Field #1, #2)	173	18	$190,000	$25,000	$1,390	$1,700
High Frequency Power Supply (Field #1)	180	11	$100,000	$13,100	$1,190	NA

Based on the above analysis, the controls that were eliminated based on cost-effectiveness under Georgia Power's PM_{10} BACT determination would also be excluded under a $PM_{2.5}$ BACT determination. Just like for PM_{10}, only the high frequency power supplies could be considered cost effective at controlling $PM_{2.5}$. Therefore, because the controls determined to be feasible and cost-effective as part of a $PM_{2.5}$ BACT determination would be exactly the same as the controls already proposed as PM_{10} BACT for the Plant Mitchell biomass conversion, the PM_{10} BACT controls and limits proposed will provide sufficient assurance of BACT for $PM_{2.5}$ as well.

In addition to the above, the following considerations are provided to explain why EPD has determined that PM_{10} should serve as the surrogate for $PM_{2.5}$ in this PSD determination:

There is a strong statistical relationship between PM_{10} and $PM_{2.5}$ Emissions. $PM_{2.5}$ is a subset of PM_{10}; all $PM_{2.5}$ will be included in PM_{10} evaluations. Further, there is a predictable correlation between $PM_{2.5}$ and PM_{10} emissions and control efficiencies from emission units associated with the project, consistent under the range of operating scenarios and conditions expected. The degree of control for both PM_{10} and $PM_{2.5}$ are influenced by the same control device operating parameters, such that proper operation of the control devices to minimize PM_{10} emissions (as well as additional control train equipment installed for other purposes) will simultaneously minimize $PM_{2.5}$ emissions.

The BACT selected for PM_{10} is also the most effective technology (and would be considered BACT) for $PM_{2.5}$ emissions.

US EPA has yet to establish final values for significant impact level (SIL) or PSD Increment. In addition, EPA has yet to establish a final Minor Source Baseline Date. While EPA has recently proposed three possible values for these levels, the SIL and increment are likened to a moving target, if and when EPA sets the final values, they may be any one of the proposed values, or a completely different value. US EPA Region 4 itself commented to EPD (regarding the Plant Washington Preliminary Determination), questioning EPD's decision to use the most stringent of the proposed SILs.

There is insufficient technical guidance from US EPA regarding measurement of $PM_{2.5}$. There is not currently an accurate and accepted methodology for quantifying both filterable and condensable $PM_{2.5}$ emissions for most types of emission sources. For filterable $PM_{2.5}$, short of assuming all PM is $PM_{2.5}$, there is no EPA-approved test method currently in place. This is particularly true for sources with stack emissions containing condensed water droplets. For condensable $PM_{2.5}$, existing test methods have been shown to produce inconsistent and variable results that can also be biased high due to artifacts. For this reason, EPA chose to adopt a transition period in the final $PM_{2.5}$ implementation rule during which PSD permits would not need to address condensable $PM_{2.5}$ emissions. Due to the lack of accurate and available test methods, there is limited data available on $PM_{2.5}$ emissions (both filterable and condensable) for most types of emission sources. While data that is available may be useful for defining general correlations and relationships between $PM_{2.5}$ and other pollutants, it is not of sufficient quantity or accuracy for setting emission limits. This lack of information would not only affect the setting of $PM_{2.5}$ BACT limits, but would restrict an accurate $PM_{2.5}$ emissions inventory for contributing/nearby sources to be considered in any NAAQS or PSD Increment modeling.

Background concentrations of $PM_{2.5}$ are not well established. While Georgia has begun a $PM_{2.5}$ monitoring campaign, the data may not accurate enough to use as a background concentration when comparing to the $PM_{2.5}$ NAAQS.

Georgia's SIP has yet to be amended to include $PM_{2.5}$. EPA promulgated its final NSR/PSD implementation rule for $PM_{2.5}$ in May 2008, but expressly recognized that use of the PM_{10} Surrogate Policy would be continued until SIP-approved permitting programs revise the SIP to include $PM_{2.5}$. The deadline for this revision is May 2011. EPD did not identify any technical prerequisites to application of the PM_{10} Surrogate Policy. In fact, EPA elected not to finalize a previously proposed option that would have required sources to demonstrate compliance with the $PM_{2.5}$ NAAQS, because "partially implementing the PM_{10} Surrogate Policy in this manner would be confusing and difficult to administer."

Conclusion

Because the controls proposed as part of Georgia Power's $PM_{2.5}$ BACT determination for the Plant Mitchell biomass conversion would not differ in any way from those that would be selected as $PM_{2.5}$ BACT for the project, PM_{10} is a reasonable surrogate for $PM_{2.5}$ for the biomass conversion project.

EPD Review – $PM_{2.5}$ Control

In addition to reviewing the permit application and supporting documentation, the Division has performed independent research of the $PM_{2.5}$ BACT analysis and used the following resources and information:

- USEPA RACT/BACT/LAER Clearinghouse[4]
- Final/Draft Permits and Final/Preliminary Determinations for similar biomass project permits such as Sappi Cloquet LLC
- Minnesota Pollution Control Agency, Air Quality Division, Toni Volkmeier
- Minnesota Pollution Control Agency, Air Quality Division, Technical Support Document and Air Emission Permit No. 01700002-012, Sappi Cloquet LLC, Cloquet, MN, 10/28/2009

On May 8, 2008, EPA issued a rule that finalizes several NSR program requirements for sources that emit $PM_{2.5}$ and other pollutants that contribute to $PM_{2.5}$. This rule became effective on July 15, 2008. The rule adopts a significant emission rate of 10 tons per year for direct $PM_{2.5}$ emissions as well as other levels for pollutants that contribute to $PM_{2.5}$ (including SO_2 , NOx, and VOC). However, the new rule contains a transition policy that suggests SIP-approved states should continue to use PM_{10} as a surrogate for $PM_{2.5}$ in attainment areas until the state revises its SIP. Therefore, since Plant Mitchell is located in an attainment area for $PM_{2.5}$ (Dougherty County), the new rule does not apply until Georgia revises its SIP.

$PM_{2.5}$ can be emitted directly from a source or formed secondarily in the atmosphere from emissions of other compounds referred to as precursors. The new rule will eventually address both filterable and condensable direct $PM_{2.5}$ emissions. However, due to uncertainties in existing data for condensable $PM_{2.5}$, the new $PM_{2.5}$ rule contains a "transition period" during which NSR permits need not address direct condensable $PM_{2.5}$ emissions. The transition period extends until 2011 or until sufficient advances are made in the test methods for measuring $PM_{2.5}$ to enable accurate and reliable measurements. Directly

[4] http://cfpub1.epa.gov/rblc/htm/bl02.cfm

emitted $PM_{2.5}$ is addressed below while other pollutants that may contribute to $PM_{2.5}$ are addressed in other respective sections of this BACT analysis.

Very limited information and data exist concerning the characterization of $PM_{2.5}$ emissions from wood residue combustion. A review of EPA AP-42 Emission Factors indicates the following:

- Section 1.6 (Wood Residue Combustion in Boilers) contains PM emission factors for filterable $PM_{2.5}$ calculated from cumulative mass in percent as provided in Table 1.6-5 for Bark and Wet Wood-fired boilers multiplied by the Filterable PM factor.

Accordingly, the facility assumed all PM_{10} is also $PM_{2.5}$. This is not a guaranteed emission value but it is simply an estimate. Using this assumption as an upper bound, primary $PM_{2.5}$ emissions (filterable) would not exceed the level of primary (filterable) PM_{10} emissions.

Based on a review of the RBLC for $PM_{2.5}$, only one wood-fired stoker project is listed. The Sappi Cloquet, LLC is a kraft process pulp and paper mill. The facility permit is dated October 28, 2009. The currently operating wood-fired boiler (Source Code: EU 004) has an existing multiclone and ESP. These controls were deemed BACT. The $PM_{2.5}$ BACT limit is 13.5 lb/hr for a three-hour average. The boiler is subject to this limit after NOx control modifications are made to the boiler. Toni Volkmeier of the Minnesota Pollution Control Agency, Air Quality Division was contacted to inquire as to how this limit was established. The facility performed modeling and relied upon the latest PM_{10} test results of 1.6 lbs/hr, a value much lower than the permit limit of 30 lbs/hr. Due to the uncertainty in $PM_{2.5}$ test methods, a more conservative value of 13.5 lbs/hr was set for the $PM_{2.5}$ BACT limit. The facility will show compliance by initial and periodic testing at intervals determined by test results.

EPD Review - Conclusion – $PM_{2.5}$ Control

GA EPD agrees that a separate BACT limit of $PM_{2.5}$ aside from PM_{10} is not proposed at this time for the reasons stated. The facility will be using PM_{10} emissions as a surrogate to estimate $PM_{2.5}$ emissions.

SG03 – CO Emissions

Applicant's Proposal

Step 1: Identify All Control Technologies

CO and VOC emissions are generated from incomplete combustion of carbon-containing fuels. CO and VOC formation is affected by combustion temperature, residence time, and oxygen levels in the combustion zone. Reduced combustion temperature, insufficient residence time, and low oxygen levels result in increased formation of CO and VOC. CO emissions can be used as an indicator of VOC emissions and low CO emissions virtually always indicate low VOC emissions. In addition, the emissions of both CO and VOCs are minimized by the same available controls.

CO and VOC emission can be reduced by controlling the combustion process or by post-combustion oxidation systems. The following methods evaluated in Section 4.2.2 of the application are as follows:

- Combustion Control
- Post Combustion Control – Catalytic Oxidation
- Post Combustion Control – Thermal Oxidation

Combustion Control

A modern biomass spreader stoker/suspension burn design minimizes combustion problems. Air is introduced to the combustion zone in three or four different areas including under the grate, just above the grate, in the pneumatic fuel conveyor and as over fire air (OFA). Careful control of the various air locations and quantities ensure complete fuel burnout and minimization of CO and VOC emissions.

For the details of the facility's evaluation of combustion control, please refer to Section 4.2.2.

Post Combustion Control – Catalytic Oxidation

For the details of the facility's evaluation of post combustion control- catalytic oxidation, please refer to Section 4.2.2.

Post Combustion Control – Thermal Oxidation

For the details of the facility's evaluation of post combustion control- thermal oxidation, please refer to Section 4.2.2.

Step 2: Eliminate technically infeasible options

Post Combustion Control – Catalytic Oxidation

Although Catalytic oxidation has been used successfully to reduce CO and VOC emissions from gas and oil-fired turbines, its application to biomass-fired steam generating units has been rare. In order to prevent catalyst plugging and fouling, the CO oxidation catalyst must be installed after particulate matter (PM_{10}) controls. However, the exhaust gas temperature after the PM_{10} controls at Plant Mitchell is expected to be between 320 ^{o}F and 380 ^{o}F. These temperatures are well below the optimum catalyst operating temperature range (700 ^{o}F – 1,100 ^{o}F) and are even below the point at which virtually no emission reductions are expected (380 ^{o}F).

In Section 4.2.3 of the application the facility discusses it's review of the EPA RBLC database, and the proposed facility in Ohio named Southpoint Biomass Generation that plans to install a CO oxidation catalyst system. However, this facility has not yet completed construction or performed any testing so the actual effectiveness of the catalyst in not yet known.

In Section 4.2.3 of the application, the facility also discusses two other small biomass-fired steam generating units in New Hampshire that have installed oxidation catalysts for CO emission control that are not listed in the RBLC database. These facilities are known as “BioEnergy” and “DG Whitefield”. The BioEnergy permit has expired and a CO efficiency was not available. The DG Whitefield facility demonstrated an average CO removal efficiency of over 75%.

In Section 4.2.3 of the application, the facility also discusses Plant Carl, in Franklin County, Georgia and references, the Yellow Pine BACT Analysis. Plant Carl expected a removal efficiency of 25-50 percent. The oxidation catalyst has not been installed or operated in order to verify the actual removal efficiency at the facility.

GA EPD points out that the flue gas through the catalyst at all of the above mentioned facilities is 400 ^{o}F or higher while Plant Mitchell plans to operate between 320 ^{o}F and 380 ^{o}F.

In the remainder of Section 4.2.3, the facility discusses why a CO oxidation catalyst is not technically feasible for Plant Mitchell. The Division asked the permit applicant to provide more justification why a carbon monoxide catalyst following a Hot Side ESP is not feasible for the Mitchell Biomass Project. Georgia Power provided justification in an information package dated on November 12, 2009, located in Appendix B.

Post Combustion Control – Thermal Oxidation

For the details of the facility’s feasibility analysis of post combustion control- thermal oxidation, please refer to Section 4.2.3.

Step 3: Ranking of Available Control Techniques

After a review of available post combustion controls for CO and VOC (i.e. catalytic oxidation and thermal oxidation) it was determined that these controls are not technically feasible for the Mitchell Biomass Project. Best combustion practices for maximizing steam generating unit efficiency is the only technically feasible control for reducing CO and VOC emissions from this Biomass Project.

Step 4: Most Effective Control

The most effective control is the use of best combustion practices for maximizing steam generating unit efficiency.

Step 5: Selection of BACT

<u>BACT Emission Limitation for CO</u>.

Please refer to Section 4.2.4 of the application for the details of the determination of the CO BACT limit.

Based on the facility’s analysis and a review of the EPA RACT/BACT/LAER Clearinghouse (RBLC) and other sources of information, Plant Mitchell has proposed best combustion practices as BACT control technology and a BACT limit for CO as 0.45 lb/mmBtu on a 30-day rolling average. This limit is based on the maximum degree of reduction that will be achievable by Plant Mitchell on a continuous basis after it has been converted to a biomass steam generating unit. This limit is justified considering the range of permitted limits identified (the proposed limit is in the lower end of the range) and the differences in technology issues associated with many of the other projects reviewed.

EPD Review – CO Control

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

- USEPA RACT/BACT/LAER Clearinghouse[5]
- Final/Draft Permits and Final/Preliminary Determinations for similar biomass project permits such as Multitrade, Yellow Pine, and Plant Carl
- Title V Operating Permit for BioEnergy, LLC, West Hopkinton, NH, September 12, 1995, the Addendum dated March 3, 1997 and modification dated June 21, 2002
- Title V Operating Permit for Whitefield Power and Light Company, NH, January 11, 1999, the Amendment dated November 15, 1999, April 12, 2000, June 26, 2001 and November 15, 2001
- Washington State Department of Ecology, PSD-01-07 Amendment I issued on June 20, 2002, Boise Cascade Corporation, Wallula Mill, Wallula, WA
- NSR Narrative and Permit No. 3434, Western Water and Power Production LLC, Estancia Basin Biomass Power Generation Plant, Alburquerque, NM, March 29, 2007
- Massachusetts Division of Energy Resources, Renewable Energy Portfolio Standard, Statement of Qualification, Schiller Station Unit 5, December 1, 2006
- Temporary PSD permit No. TP-B-0501, Schiller Station Unit 5, March 7, 2006
- Minnesota Pollution Control Agency, Air Quality Division, Technical Support Document and Air Emission Permit No. 01700002-012, Sappi Cloquet LLC, Cloquet, MN, 10/28/2009
- Biomass Group, LLC, South Point Power, Final Permit to Install Modification, South Point, Lawrence County, Ohio, issued 4/4/2006
- Biomass Group, LLC, South Point Power, Permit to Install Application, Particulate Matter and Carbon Monoxides BACT Analysis, South Point, Lawrence County, Ohio, Revision 5, 9/23/04
- Biomass Group, LLC, South Point Power, Request for Proposal, South Point, Lawrence County, Ohio, 10/15/2003

The Division has prepared BACT comparison spreadsheets for all pollutants for the similar units using the above-mentioned resources and they are attached in Appendix D.

The Division also reviewed Table 4-1 of the application, other facility permits and the RBLC database. Four facilities with wood steam generating units of a comparable size had a weighted average CO BACT limit of 0.36 lb/mmBtu. Although the averaging period was not specified in every case, the proposed 30 day rolling average would apply for this limit also. This factor 0.36 lb/mmBtu is comparable to the 0.45 lb/mmBtu CO BACT limit proposed by GA Power, considering the uniqueness of the project. The Division asked the permit applicant to provide more justification and references in support of the limit. GA Power provided the following justification:

GA Power's response is as follows:

As mentioned previously, several factors create a unique situation at Plant Mitchell that must be considered in the air permit. As discussed in the application, there was a wide range (0.196 - 6.500 lb/mmBtu) of permitted CO emission limits presented in the RBLC database and discovered through additional research. Again, GA Power limited their analysis to stoker or unknown type steam generating units. Of the facilities that were examined, the S.D. Warren in Maine is the most comparable in size to the Mitchell project at 1300 mmBtu/hr. The limit imposed at that facility is 0.40 lb/mmBtu but the averaging period is not specified. The next largest facility in the RBLC for CO was US Sugar in Florida.

[5] http://cfpub1.epa.gov/rblc/htm/bl02.cfm

The limit there is 0.38 lb/mmBtu but averaged annually instead of over 30 days. Thus, GA Power believes the proposed CO BACT limit of 0.45 lb/mmBtu averaged over 30 days at Plant Mitchell compares well to these facilities. Other relatively large facilities, such as the Fibrominn Biomass plant in Minnesota at 792 mmBtu/hr, are new facilities and the BACT limits for new facilities cannot necessarily be applied to retrofit projects like Plant Mitchell.

The Alstom engineering study referenced in the application predicts CO emissions from Mitchell to be as low as 0.3 lb/mmBtu. However, Georgia Power has not received a performance guarantee of this emission level and neither Alstom nor Georgia Power has any previous operating experience with a biomass steam generating unit similar to Mitchell SG03. Thus, Georgia Power believes that the limit of 0.45 lb/mmBtu is both reasonable compared to other facilities and provides the necessary compliance margin to account for the uncertainties associated with this unique project. Therefore, GA EPD agrees with limit as proposed by Georgia Power.

<u>Conclusion – CO Control</u>

The BACT selection for the SG03 is summarized below in Table 4-11:

Table 4-11: BACT Summary for unit SG03

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
CO	Good Combustion Practices	0.45 lb/mmBtu	30 day rolling average	CEMS

SG03 – VOC Emissions

Applicant's Proposal

Formation of VOC emissions in biomass-fired steam generating units is attributable to the same factors as described for CO emissions in the section above. VOC emissions are a result of incomplete combustion of carbonaceous fuels, and this is influenced by the temperature and residence time within the combustion zone.

Step 1: Identify All Control Technologies

Please refer to the discussion on CO Emissions.

In addition, GA EPD requested GA Power, to consider carbon absorption and carbon adsorption as potential VOC controls in their BACT Analysis. In the following section, GA Power eliminated carbon absorption and carbon adsorption as a feasible control for the biomass-fired steam generating unit application.

Step 2: Elimination of Infeasible Controls

After a review of available post combustion controls for CO and VOC (i.e. adsorption, absorption, catalytic oxidation and thermal oxidation), it was determined that these controls are not technically feasible for the Mitchell Biomass Project. Best combustion practices for maximizing steam generating unit efficiency is the only technically feasible control for reducing CO and VOC emissions from this Biomass Project.

Please refer to the item 2 response in the Additional Information Package received on May 29, 2009, located in Appendix B for further detail on the elimination of infeasible controls.

Step 3: Ranking of Available Control Techniques

The only available control technique is the use of Best Combustion Practices.

Step 4: Most Effective Control

The most effective control is the use of best combustion practices for maximizing steam generating unit efficiency.

Step 5: Selection of BACT

As can be seen in Table 4-2 of the application, for VOC there is a wide range (0.019 - 0.500 lb/mmBtu) of permitted emission limits presented in the RBLC and discovered through additional research. GA Power limited their analysis to stoker or unknown type steam generating units.

Please refer to the item 3 response in the Additional Information Package received on May 29, 2009, located in Appendix B, for further detail on the justification for the proposed VOC limit of 0.05 lb/mmBtu.

Formation of VOC Emissions in biomass-fired steam generating units is attributable to the same factors as described for CO emissions in the section above. VOC emissions are a result of incomplete combustion of carbonaceous fuels, and this is influence by the temperature and residence time within the combustion zone.

Conclusion – VOC Control

From the facility's analysis and a review of the EPA RACT/BACT/LAER Clearinghouse (RBLC) and other sources of information, GA Power proposes BACT for VOC to be best combustion practices and the VOC BACT limit of 0.05 lb/mmBtu on a 3 hour average.

EPD Review – VOC Control

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

- USEPA RACT/BACT/LAER Clearinghouse[6]
- Final/Draft Permits and Final/Preliminary Determinations for similar biomass project permits such as Multitrade, Yellow Pine, and Plant Carl
- Title V Operating Permit for BioEnergy, LLC, West Hopkinton, NH, September 12, 1995, the Addendum dated March 3, 1997 and modification dated June 21, 2002
- Title V Operating Permit for Whitefield Power and Light Company, NH, January 11, 1999, the Amendment dated November 15, 1999, April 12, 2000, June 26, 2001 and November 15, 2001
- NSR Narrative and Permit No. 3434, Western Water and Power Production LLC, Estancia Basin Biomass Power Generation Plant, Albuquerque, NM, March 29, 2007
- Massachusetts Division of Energy Resources, Renewable Energy Portfolio Standard, Statement of Qualification, Schiller Station Unit 5, December 1, 2006

The Division has prepared BACT comparison spreadsheets for all pollutants for the similar units using the above-mentioned resources and they are attached in Appendix D.

GA EPD reviewed the above resources and is in agreement with the proposed limit of 0.05 lb/mmBtu, which is reasonable compared to other comparable sized facilities and provides the necessary compliance margin to account for the uncertainties associated with this unique project.

Conclusion – VOC Control

The BACT selection for SG03 is summarized below in Table 4-12:

Table 4-12: BACT Summary for SG03

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
VOC	Best Combustion Practices	0.05 lb/mmBtu	3 hour average	Method 25, Method 320 (Initial and Annual Testing)

[6] http://cfpub1.epa.gov/rblc/htm/bl02.cfm

Biomass Delivery, Storage and Handling [Biomass Handling (Source Code: BHS): Driveway, Truck Scales, Truck Unloading, Four Truck Tippers, Hog/Screen Tower, Metal Detectors, Magnetic Separators, Two Circular Stacker/Reclaimers, Two Storage Piles, Conveyor System, Two Silos, Fines Silo] - Particulate matter less than 10 micrometers in diameter (PM_{10}) Emissions

Fugitive PM_{10} emission sources associated with the proposed project include: the truck unloading area, conveyor transfer stations, biomass storage piles, radial stacker and reclaimer, and plant roadways. Fugitive PM_{10} emissions associated with the proposed project result primarily from the mechanical agitation on conveyors and at transfer points, wind erosion of storage piles, or vehicular traffic on the paved roadways onsite.

Applicant's Proposal

In Application 18663, Plant Mitchell evaluated pre and post combustion control technologies for the material storage and handling equipment listed above. The control technologies evaluated, as described in Application 18663, are as follows:

Step 1: Identify all control technologies

- Lower emitting processes and practices for the control of PM/PM_{10} emissions are controls that lower the PM/PM_{10} generation rate. Examples of lower emitting processes and practices for control of PM/PM_{10} emissions include the conditioning of a material prior to transport, compacting storage piles, and limiting speeds on plant roads. Add-on controls prevent the release of PM/PM_{10} or remove PM/PM_{10} from the air. Water and surfactant sprays, surface sealants, and enclosures are examples of the implementation of add-on controls for PM/PM_{10} emissions. Water and surfactant sprays control the creation of PM/PM_{10} emissions by binding the smaller particles to the surface of the material, or by actively suppressing PM/PM_{10} emissions through direct contact between spray droplets and PM/PM_{10} within the air. Surface sealants are chemical treatments that create a protective layer on the surface of the material to bind and contain PM/PM_{10}. Enclosures control PM/PM_{10} emissions by isolating the PM/PM_{10} source from the environment. Examples of types of enclosures include material transfer chutes, conveyor hooding, and storage pile covers.

Step 2: Eliminate technically infeasible options

- Examples of technically infeasible applications would include the use of sprays that may cause a chemical reaction, violate the integrity of the biomass fuel, and cause frequent disturbance of the active storage piles.

- Application of water in freezing weather is also infeasible. Water sprays and flushes are only considered a technically feasible control option for reducing silt emissions from plant biomass transport roadways.

- Given the inherently high moisture content of the biomass fuel itself, further water spraying of the fuel at the unloading area, on the storage piles, or on conveyors would compromise the integrity of the fuel and affect fuel quality and combustion efficiency.

- Compaction is not considered a technically feasible method of controlling PM_{10} emissions from the biomass storage piles given the frequent disturbance of these active storage piles.

- Applying full enclosures to control fugitive PM_{10} emissions is not considered feasible considering functional, practical, and safety considerations. However partial enclosures (e.g. three-quarter hoop covers are considered a technically feasible control for controlling fugitive PM_{10} emissions for conveyors and transfer points. These covers will provide for significant emissions control while allowing for safe maintenance access and visible observation of operation.

- Limiting Vehicle speeds and Vacuum Sweeping are considered a technically feasible control option for reducing silt emissions from plant biomass transport roadways.

Step 3: Ranking the Remaining Control Technologies by Control Effectiveness

For biomass conveyors and transfer points, partial enclosures (i.e., three-quarter hoop covers) will be used to minimize PM_{10} emissions. These partial enclosures are expected to reduce PM_{10} emissions by approximately 70 percent[7].

For fugitive emissions from plant roadways, the application of water sprays (for unpaved roads) and water flushing (for paved roads) can effectively reduce silt emissions from plant roads. Water sprays on unpaved roads and water flushing on paved roads are expected to reduce PM_{10} emissions by 86 percent[8] and 80 percent[9], respectively. Vacuum sweeping of paved roads could also be effective in reducing silt emissions by 75 percent. In addition, maintaining lower vehicle travel speeds on plant roadways will further minimize the suspension of dust (silt) from road surfaces[10]. Water sprays (for unpaved roads), water flushing (for paved roads), and limiting vehicle speeds on plant roadways have been accounted for in the road dust emission factors. Vacuum sweeping was not included since it has a lower control effectiveness than water flushing of paved roads.

Step 4: Evaluating the Most Effective Controls and Documentation

The most effective controls are water flushing for new paved roles for biomass delivery, water sprays for unpaved roadways for potential chipping operations, partial enclosures for all conveyors and transfer points, and lower vehicle travel speeds.

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[7] Simmons, L. L. and L. E. Lambert. 2000. Coal Processing. In W. Davis (Ed.) *Air Pollution Engineering Manual, Second Edition*. (Air and Waste Management Association) pp. 690-695 (table 4). New York : John Wiley & Sons, Inc.

[8] Watson, J. G., J. C. Chow, and T. G. Pace. 2000. Fugitive Dust Emissions. In W. Davis (Ed.) *Air Pollution Engineering Manual, Second Edition*. (Air and Waste Management Association) pp. 117-135. New York : John Wiley & Sons, Inc.

[9] EPA, 1988a. Control of Open Fugitive Dust Sources. Table 2.1.1-3. EPA-450/3-88-008. U.S. Environmental Protection Agency, OAQPS, Research Triangle Park, NC. September.

[10] Watson, J. G., J. C. Chow, and T. G. Pace. 2000. Fugitive Dust Emissions. In W. Davis (Ed.) *Air Pollution Engineering Manual, Second Edition*. (Air and Waste Management Association) pp. 117-135. New York : John Wiley & Sons, Inc.

Step 5: Selection of BACT

The facility has proposed the following information as presented in Table 4-13 for BACT.

Table 4-13 Proposed BACT for Fugitive PM_{10} Emissions

Emissions Control Method	**Emissions Source**
Water flushing	New Paved Roadways for Biomass Delivery
Water spray	Unpaved Roadways for Potential Chipper Operations
Lower vehicle travel speeds[11]	New Paved Roadways for Biomass Delivery
	Unpaved Roadways for Potential Chipper Operations
Partial enclosures (three-quarter hoop covers)	All Conveyors and Transfer Points

<u>EPD Review - Biomass Delivery, Storage and Handling [Biomass Handling (Source Code: BHS): Driveway, Truck Scales, Truck Unloading, Four Truck Tippers, Hog/Screen Tower, Metal Detectors, Magnetic Separators, Two Circular Stacker/Reclaimers, Two Storage Piles, Conveyor System, Two Silos, Fines Silo] - Particulate matter less than 10 micrometers in diameter (10) Emissions</u>

In addition to reviewing the permit application and supporting documentation, the Division has performed independent research of the PM_{10} BACT analysis and used the following resources and information:

- USEPA RACT/BACT/LAER Clearinghouse[12]
- Final/Draft Permits and Final/Preliminary Determinations for similar biomass project permits such as Yellow Pine.
- NSR Narrative and Permit No. 3434, Western Water and Power Production LLC, Estancia Basin Biomass Power Generation Plant, Albuquerque, NM, March 29, 2007

The Division has determined that Plant Mitchell's proposal to use water sprays and enclosures as proposed to minimize the emissions of PM_{10} does constitute BACT.

[11] Watson, J. G., J. C. Chow, and T. G. Pace. 2000. Fugitive Dust Emissions. In W. Davis (Ed.) *Air Pollution Engineering Manual, Second Edition*. (Air and Waste Management Association) pp. 117-135. New York : John Wiley & Sons, Inc.
[12] http://cfpub1.epa.gov/rblc/htm/bl02.cfm

Conclusion - Biomass Delivery, Storage and Handling [Biomass Handling (BHS): Driveway, Truck Scales, Truck Unloading, Four Truck Tippers, Hog/Screen Tower, Metal Detectors, Magnetic Separators, Two Circular Stacker/Reclaimers, Two Storage Piles, Conveyor System, Two Silos, Fines Silo] - Particulate matter less than 10 micrometers in diameter (PM_{10}) Emissions

The BACT selection for the Material Storage and Handling is summarized below in Table 4-14:

Table 4-14: BACT Summary for the Material Storage and Handling

Pollutant	Control Technology	Proposed BACT Limit	Compliance Determination Method
PM_{10}	Water sprays for Unpaved Roadways for Potential Chipper Operations	None	Monitoring
PM_{10}	Partial Enclosures for the conveyors	None	Monitoring
PM_{10}	Partial Enclosures for the transfer points	None	Monitoring

WC03 Wood Chipping Unit- Background

As mentioned in the process description in Section 2, Georgia Power may install an onsite wood chipping operation to backup and supplement the primary fuel supply. This operation would use a diesel engine driven wood chipper. Although this equipment has not yet been selected, a model CBI 8400-P Magnum chipper driven by a Caterpillar C27 ACERT Model diesel engine with a maximum rated capacity of 1,050 bhp is representative of the type of equipment that would be purchased. The engine would be fired with ultra-low sulfur diesel (ULSD) fuel oil with a maximum sulfur content of 15 ppmw. Based on the maximum processing capacity of the wood chipper of 150 tph, the engine will operate no more than 3,000 hours per year to process a maximum of 450,000 tons of wood annually.

WC03 – PM_{10} Emissions

Applicant's Proposal

Particulate matter emitted from diesel engines is comprised of four components: solid carbon soot, volatile and semi-volatile organic matter, inorganic solids (ash), and sulfates. The formation mechanism for each of these components varies with engine design and fuel composition.

The formation of the solid carbon soot portion of PM_{10} is inherent in diesel engines due to the heterogeneous distribution of fuel and air in a diesel combustion system. Within the excess fuel region of the fuel-injection plume, PM_{10} is formed when high temperatures and a lack of oxygen cause the fuel to pyrolize, forming soot. Any soot that is not fully oxidized before the exhaust valve is opened is emitted from the engine as diesel PM_{10}.

The volatile and semi-volatile organic material in diesel PM_{10}, commonly referred to as the soluble organic fraction (SOF), is primarily composed of engine oil that passes through the engine with only partial oxidation and condenses in the atmosphere to form PM_{10}. The inorganic solids (ash) in diesel comes primarily from metals found in engine oil and to a certain extent from engine wear. The sulfate portion of diesel PM_{10} is formed from sulfur present in diesel fuel and engine lubricating oil that oxidizes to form sulfuric acid (H_2SO_4) and then condenses in the atmosphere to form sulfate PM_{10}.

Step 1: Identify All Control Technologies

The emissions control technologies for filterable PM_{10} gas emissions from a diesel engine include both in-cylinder controls and post-combustion controls. The following methods evaluated in Section 4.2.5 of the application are as follows:

- In-Cylinder Controls
- Diesel Oxidation Catalysts
- Catalyzed Diesel Particulate Filter

Step 2: Eliminate technically infeasible options

All of the controls discussed are considered technically feasible, but the effectiveness of each control varies by the manufacturer's design.

Step 3: Ranking the Remaining Control Technologies by Control Effectiveness

The facility did not rank the control technologies by control effectiveness.

Step 4: Evaluating the Most Effective Controls and Documentation

Refer to Section 4.5.2 of the application for details on In-Cylinder Controls, Diesel Oxidation Catalysts, and Catalyzed Diesel Particulate Filters.

These control techniques continue to evolve to comply with the ever more stringent emissions standards established in the NSPS for Compression Ignition Internal Combustion Engines promulgated by the EPA in July 2005 (40 CFR 60, Subpart IIII).

Step 5: Selection of BACT

Proposed BACT for Potential Wood Chipper Diesel Engine

The NSPS for diesel engines defers to the regulations governing emissions from non-road compression ignition internal combustion engines promulgated by the EPA under 40 CFR Parts 89, and 1039. These standards are intended to mandate improvements in the performance of diesel engine controls over a period of years. To comply with these technology-forcing regulations, the various diesel engine manufacturers may elect to employ in-cylinder and/or post-combustion controls. The proposed engine complies not only with the Tier 2 emissions standard promulgated under 40 CFR 89.112, but also the Tier 4 standard under 40 CFR 1039.101. Using a diesel engine that complies with the NSPS for Compression Ignition Internal Combustion Engines, using ULSD fuel oil, and limiting operation of the diesel engine to a maximum of 3,000 hours per year, are considered representative of BACT for PM_{10}, CO, and VOC for the potential wood chipper diesel engine.

GA Power conducted a review of the RBLC and state databases to determine the PM_{10}, CO and VOC emission limits imposed on emergency diesel generators around the country. This review identified no diesel engines with or without an oxidation catalyst that has been permitted within the past 10 years that meet the emissions rates of the proposed engine. As such, GA Power has proposed the following information as presented in Table 4-16 for BACT.

Table 4-16 Proposed BACT for Potential Chipper Diesel Engine

Pollutant	Emissions Control Method
CO	Compliance with the new non-road NSPS, use of ultra-low sulfur diesel fuel, and 3000 hour operation limit
VOC	
PM_{10}	

EPD Review – Particulate matter less than 10 micrometers in diameter (PM_{10}) Control

In addition to reviewing the permit application and supporting documentation, the Division has performed independent research of the PM_{10} BACT analysis and used the following resources and information:

- USEPA RACT/BACT/LAER Clearinghouse[13]

The Division has prepared BACT comparison spreadsheets for all pollutants for the similar units using the above-mentioned resources and they are attached in Appendix D.

[13] http://cfpub1.epa.gov/rblc/htm/bl02.cfm

After reviewing the EPA RBLC Database, GA EPD agrees that the BACT Control Technology selection is compliance with the NSPS Subpart IIII limit as defined for the Sabine Pass LNG, LP facility permit for the state of Louisiana on November 04, 2004. GA EPD also has verified that there is no diesel engine that has been permitted in the last ten years with an oxidation catalyst control technology for the control of PM_{10}. GA EPD has confirmed that the Creole Trail LNG Import Terminal facility in Louisiana, has CO and VOC limits (0.3 lb/hr and 0.04 lb/hr) that are somewhat less than the proposed diesel engine limits, yet this is a smaller 660 hp engine. GA EPD agrees that BACT is also the proposed 3000 hours limit, after comparing the Diesel Engine Specifications, the 3000 hours operational limit, and the PM_{10}, VOC and CO limits in the RBLC. Ford Electronics of Pennsylvania, permitted in June 19, 2000, and Badger Generating Co, LLC of Wisconsin, permitted in September 20, 2000, also have hourly limits for diesel engines. The BACT review spreadsheet can be found in Appendix D.

The Division agrees with BACT except that the Control Technologies rating by control effectiveness was inconclusive due to the variability of the manufacturer's design.

Conclusion – Particulate matter less than 10 micrometers in diameter (PM_{10}) Control

GA EPD concludes that the combination of the NSPS Subpart IIII requirements, the 3000 hours operational limit and the use of ultra-low sulfur diesel fuel comprise BACT Control Technology for the proposed diesel engine for the wood chipping unit (Source Code: WC03).

The BACT selection for the Diesel Engine for the wood chipping unit (Source Code: WC03) is summarized below in Table 4-17.

Table 4-17: BACT Summary for the Diesel Engine for the wood chipping unit

Pollutant	Control Technology	Proposed BACT Limit	Compliance Determination Method
PM_{10}	Ultra-Low Sulfur Fuel	3000 hr limit, NSPS Subpart IIII	Monitoring, Fuel Certifications, Vendor Certification
CO	Ultra-Low Sulfur Fuel	3000 hr limit, NSPS Subpart IIII	Monitoring, Fuel Certifications, Vendor Certification
VOC	Ultra-Low Sulfur Fuel	3000 hr limit, NSPS Subpart IIII	Monitoring, Fuel Certifications, Vendor Certification

WC03 – CO Emissions

Applicant's Proposal

Carbon monoxide is a relatively inert gas formed as an intermediate combustion product that appears in the exhaust when the reaction of CO to CO_2 cannot proceed to completion. This situation occurs if there is a lack of available oxygen during combustion, if the gas temperature is too low, or if the residence time in the cylinder is too short.

EPD Review

Please refer to the discussion for control technologies effective for PM_{10} as it would apply for CO. GA EPD agrees with the applicant's proposal.

WC03 – VOC Emissions

Applicant's Proposal

Hydrocarbons are composed of a wide variety of organic compounds discharged to the atmosphere when some of the fuel remains unburned or is only partially burned during the combustion process.

An oxidation catalyst designed to control CO would provide an additional benefit of controlling VOC emissions by an order of 20 percent. The same technical factors that apply to the use of oxidation catalyst technology for control of CO emissions (narrow operating temperature range, loss of catalyst activity over time, and system pressure losses) apply to the use of this technology for collateral control of VOC.

EPD Review

Please refer to the discussion for control technologies effective for PM_{10} as it would apply for CO and VOC. GA EPD agrees with the applicant's proposal.

5.0 TESTING AND MONITORING REQUIREMENTS

Requirements for NO_x

The Acid Rain regulations require that the NO_x mass emission rate from the biomass-fired steam generating unit (Source Code: SG03) is measured and recorded. The Permittee must ensure that the NO_x CEMS meets all applicable criteria of 40 CFR Part 75, including the general requirements of 40 CFR 75.10, the specific provisions of 40 CFR 75.12, the equipment, installation, and performance specifications in Appendix A, and the quality assurance and quality control procedures in Appendix B. The recently promulgated Clean Air Interstate Rule (CAIR) also requires the monitoring of NO_x mass emissions. Satisfaction of the 40 CFR Part 75 Acid Rain NO_x monitoring requirements mentioned above, including Part 75, Subpart H (NO_x Mass Emissions Provisions), will assure compliance with the CAIR monitoring requirements.

Requirements for CO

Compliance with the BACT CO emission limitations for the biomass-fired steam generating unit (Source Code: SG03) must be demonstrated by using the CO CEMS as the method for compliance determination. There is a requirement in the draft permit for a CO CEMS for continuous monitoring.

Requirements for SO_2

The Acid Rain regulations require that SO_2 mass emissions from the biomass-fired steam generating unit (Source Code: SG03) be measured and recorded. One option for satisfying that requirement is to use applicable procedures specified in Appendix D to 40 CFR Part 75 for estimating hourly SO_2 mass emissions. SO_2 mass emissions from the biomass-fired steam generating unit (Source Code: SG03) when firing ultra low sulfur diesel fuel will be calculated based on the average sulfur content and heat content of that oil and the quantity of that oil which is burned. The sulfur content and heat content of that oil will be provided by appropriate certifications from the fuel suppliers. The Permittee will also have the flexibility to monitor the sulfur content and heat content of that oil using “as-received” samples instead of fuel-supplier certifications. The Division believes that this method of compliance is acceptable so long as the sulfur content of all oil delivered meets the applicable limit, 3% for the steam generating unit (Source Code: SG03) and 2.5% for the wood chipping unit (Source Code: WC03). The facility should be able to meet these sulfur limits. The facility is required to fire only ultra low sulfur (0.0015 wt%) no. 2 fuel oil, biodiesel, or biomass in the steam generating unit (Source Code: SG03) and only ultra low sulfur (0.0015 wt%) no. 2 fuel oil in the wood-chipping unit (WC03).

The recently promulgated Clean Air Interstate Rule (CAIR) also requires the monitoring of SO_2 mass emissions. Satisfaction of the 40 CFR Part 75 Acid Rain SO_2 monitoring requirements will assure compliance with the CAIR monitoring requirements.

Requirements for VOC

Method 25A performance testing will be the compliance determination method for VOC. There is no reliable and readily available method for longterm, continuous monitoring of VOC emissions from the type of fuel-burning equipment proposed by the Permittee.

The Division believes that no continuous monitoring of VOC emissions is required because the facility will be using good combustion practices and will only fire ultra low sulfur fuel oil, biodiesel fuel and quality wood supply as specified in Condition 3.2.4.

The facility shall conduct initial and annual performance tests for volatile organic compounds (VOC) on Steam Generating Unit 3 (Source Code: SG03). The test shall be conducted annually at approximately twelve month intervals not to exceed thirteen months between tests. The Permittee may, if test results from the previous annual tests are fifty percent or less of the limitation in Condition 3.3.8, request that testing be deferred for a period no greater than twelve months from the required annual test date.

Requirements for Particulate Matter and Opacity

In conducting the performance tests required under §60.8, Plant Mitchell must use the methods and procedures in appendix A (including fuel certification and sampling) of 40 CFR Part 60 or the methods and procedures as specified in 40 CFR 60.45b, except as provided in §60.8(b). Section 60.8(f) does not apply to 40 CFR 60.45b. The 30-day notice required in §60.8(d) applies only to the initial performance test unless otherwise specified by the Division [40 CFR 60.45(b)].

Compliance with the PM_{10} emission standards under §60.43b shall be determined through performance testing as described in paragraph (d) of 40 CFR 60.46b, except as provided in paragraph (i) of 40 CFR 60.46b. To determine compliance with the PM_{10} emission limits and opacity limits under §60.43b, Plant Mitchell must conduct an initial performance test as required under §60.8, and shall conduct subsequent performance tests as requested by the Division, using the following procedures and reference methods [40 CFR 60.46(d)(1) through (d)(7)]:

- Method 3B of appendix A of 40 CFR Part 60 is used for gas analysis when applying Method 5 of appendix A of 40 CFR Part 60.

- Method 5 of appendix A of 40 CFR Part 60 to measure the PM_{10} emissions from stationary sources.

- Method 1 of appendix A of 40 CFR Part 60 is used to select the sampling site and the number of traverse sampling points. The sampling time for each run is at least 120 minutes and the minimum sampling volume is 1.7 dscm (60 dscf) except that smaller sampling times or volumes may be approved by the Division when necessitated by process variables or other factors.

- The Division normally would use Method 9 of appendix A of 40 CFR Part 60 to determine opacity but a COMS may be used for determining the opacity of stack emissions (compliance will be demonstrated by the COMs required by NSPS).

Hours of Operation Recordkeeping for the Wood Chipping Unit

Condition No. 5.2.14 requires the installation, operation and maintenance of a non-resettable continuous monitoring system (or device) for the Wood Chipping Unit (Source Code: WC03) to track the hours of operation to show compliance with Condition No. 3.3.13.

Part 63 NESHAP

As emissions of hydrochloric acid (HCL) are expected to exceed 10 TPY based on the projected usage of the steam generating unit (Source Code: SG03), the facility is considered to be a major source for hazardous air pollutants (HAPs). Since the steam generating unit (Source Code: SG03) does not meet the definition of a “constructed” or “reconstructed” source under 40 CFR Part 63 Subpart B, Section 112(g) does not apply. The site is potentially subject to 112(j). At this time, Section 112(j) is not yet applicable.

Condition 4.2.4 requires the facility to do initial performance testing within 60 days after achieving maximum operating rate, but no more than 180 days after initial startup, for hydrogen chloride, benzene, formaldehyde, acrolein and styrene from the Steam Generating Unit (Source Code SG03). This testing is in anticipation of Section 112(j) and its potential requirements.

CAM Applicability:

The biomass-fired steam generating unit (Source Code: SG03) 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 biomass-fired steam generating unit (Source Code: SG03) uses a dry ESP (Source Code: EP03) and a Multiclone (Source Code: MC03) to control PM_{10}. The CAM plan for PM_{10} will be determined within 180 days after startup of the converted unit and after initial testing is conducted. The appropriate parameter for monitoring will be determined at that time.

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 Plant Mitchell triggers PSD review for PM_{10}, CO and VOC. An air quality analysis was conducted to demonstrate the facility's compliance with the NAAQS and PSD Increment standards for PM_{10} and CO. An additional analysis was conducted to demonstrate compliance with the Georgia air toxics program. This section of the application discusses the air quality analysis requirements, methodologies, and results. Supporting documentation may be found in the Air Quality Dispersion Report of the application and in the additional information packages.

<u>Modeling Requirements</u>

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 PM_{10}, CO and VOC 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 Increments. VOC does not have an established PSD modeling significance level (MSL) (an ambient concentration expressed in either $\mu g/m^3$ or ppm). Modeling is not required for VOC emissions; however, the project will likely have no impact on ozone attainment in the area based on data from the monitored levels of ozone in Sumter County and the level of emissions increases that will result from the proposed project. The southeast is generally NO_2 limited with respect to ground level ozone formation.

<u>Significance Analysis: Ambient Monitoring Requirements and Source Inventories</u>

Initially, a Significance Analysis is conducted to determine if the PM_{10}, CO and VOC emissions increases at the Plant Mitchell would significantly impact the area surrounding the facility. Maximum ground-level concentrations are compared to the pollutant-specific U.S. EPA-established modeling significant levels (MSLs). The MSLs for the pollutants of concern are summarized in Table 6-1.

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

Under current U.S. EPA policies, the maximum impacts due to the emissions increases from a project are also assessed against monitoring *de minimis* levels to determine whether pre-construction monitoring should be considered. These monitoring *de minimis* levels are also listed in Table 6-1. If either the predicted modeled impact from an emission increase or the existing ambient concentration is less than the monitoring *de minimis* concentration, the permitting agency has the discretionary authority to exempt an applicant from pre-construction ambient monitoring. This evaluation is required for PM_{10} and CO.

If any off-site pollutant impacts calculated in the Significance Analysis exceed the SIL, a Significant Impact Area (SIA) would be determined. The SIA encompasses a circle centered on the facility with a radius extending out to (1) the farthest location where the emissions increase of a pollutant from the project causes a significant ambient impact, or (2) a distance of 50 km, whichever is less. All sources within a distance of 50 km of the edge of a SIA are assumed to potentially contribute to ground-level concentrations within the SIA and would be evaluated for possible inclusion in the NAAQS and PSD Increment analyses. $PM_{2.5}$ does not yet have established MSLs (3 options proposed on 9/12/07)

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)
PM_{10}	Annual	1	--
	24-Hour	5	10
CO	8-Hour	500	575
	1-Hour	2000	--

NAAQS Analysis

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

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

Pollutant	Averaging Period	NAAQS	
		Primary / Secondary (ug/m^3)	Primary / Secondary (ppm)
PM_{10}	Annual	*Revoked 12/17/06	*Revoked 12/17/06
	24-Hour	150 / 150	--
$PM_{2.5}$	Annual	15 / 15	--
	24-Hour	35 / 35	--
CO	8-Hour	10,000 / None	9 / None
	1-Hour	40,000 / None	35 / None

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

PSD Increment Analysis

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

U.S. EPA has established PSD Increments for NO_X, SO_2, and PM_{10}; no increments have been established for CO or $PM_{2.5}$ (however, $PM_{2.5}$ increments are expected to be added soon). The PSD Increments are further broken into Class I, II, and III Increments. Plant Mitchell is located in a Class II area. The PSD Increments are listed in Table 6-3.

Table 6-3: Summary of PSD Increments

Pollutant	Averaging Period	PSD Increment	
		Class I (ug/m^3)	Class II (ug/m^3)
PM_{10}	Annual	4	17
	24-Hour	8	30

To demonstrate compliance with the PSD Increments, the increment-affecting emissions (i.e., all emissions increases or decreases after the appropriate baseline date) from the facility and those sources in the regional inventory would be modeled to demonstrate compliance with the PSD Class II increment for any pollutant greater than the MSL in the Significance Analysis. For an annual average analysis, the highest incremental impact will be used. For a short-term average analysis, the highest second-high impact will be used.

The determination of whether an emissions change at a given source consumes or expands increment is based on the source classification (major or minor) and the time the change occurs in relation to baseline dates. The major source baseline date for NO_X is February 8, 1988, and the major source baseline for SO_2 and PM_{10} is January 6, 1975. Emission changes at major sources that occur after the major source baseline dates affect Increment. In contrast, emission changes at minor sources only affect Increment after the minor source baseline date, which is set at the time when the first PSD application is completed in a given area, usually arranged on a county-by-county basis. The minor source baseline dates have been set for PM_{10} and SO_2 as July 6, 1979, and for NO_2 as March 1, 1995.

Modeling Methodology

Details on the dispersion model, including meteorological data, source data, and receptors can be found in EPD's PSD Dispersion Modeling and Air Toxics Assessment Review located in the EPD modeling memo dated November 9, 2009 included in Appendix C of this Preliminary Determination and in Section 6 of the permit application.

Modeling Results

Table 6-4 show that the proposed project will not cause ambient impacts of CO above the appropriate SIL. Because the emissions increases from the proposed project result in ambient impacts less than the SIL, no further PSD analyses were conducted for this pollutant.

However, ambient impacts above the SILs were predicted for PM_{10} for the 24 hour averaging period, requiring NAAQS and Increment analyses be performed for PM_{10}.

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

Pollutant	Averaging Period	Year	UTM East (km)	UTM North (km)	Maximum Impact (ug/m^3)	SIL (ug/m^3)	Significant?
PM_{10}	24-hour	2002	772.9	3482.3	56.55	5	**Yes**
	Annual	2003	772.9	3482.7	6.47	1	**Yes**
CO	1-hour	2001	771.1	3481.4	61.82	2000	No
	8-hour	2004	772.0	3481.6	40.24	500	No

Data for worst year provided only.

Please refer to the EPD modeling memo dated November 9, 2009 included in Appendix C for details of the Class II Significant Impact Analysis.

As indicated in the table above, maximum modeled impacts were below the corresponding SILs for CO. However, maximum modeled impacts were above the SILs for the 24-hour and annual PM_{10} limits. Therefore, a Full Impact Analysis was conducted for PM_{10}.

Significant Impact Area

For any off-site pollutant impact calculated in the Significance Analysis that exceeds the SIL, a Significant Impact Area (SIA) must be determined. The SIA encompasses a circle centered on the facility being modeled with a radius extending out to the lesser of either: 1) the farthest location where the emissions increase of a pollutant from the proposed project causes a significant ambient impact, or 2) a distance of 50 kilometers. All sources of the pollutants in question within the SIA plus an additional 50 kilometers are assumed to potentially contribute to ground-level concentrations and must be evaluated for possible inclusion in the NAAQS and Increment Analysis.

Based on the results of the Significance Analysis, the distance between the facility and the furthest receptor from the facility that showed a modeled concentration exceeding the corresponding SIL was determined to be less than 3.72 kilometers for PM_{10}. To be conservative, regional source inventories for this pollutant was prepared for sources located within 53 kilometers of the facility.

NAAQS and Increment Modeling

Details on the dispersion model, including meteorological data, source data, and receptors can be found in EPD's Dispersion Modeling and Air Toxics Assessment Review located in the EPD modeling memo dated November 9, 2009 included in Appendix C.

The next step in completing the NAAQS and Increment analyses was the development of a regional source inventory. Nearby sources that have the potential to contribute significantly within the facility's SIA are ideally included in this regional inventory. Plant Mitchell requested and received an inventory of NAAQS and PSD Increment sources from Georgia EPD. Plant Mitchell reviewed the data received and calculated the distance from the plant to each facility in the inventory.

The distance from the facility of each source listed in the regional inventories was calculated, and all sources located more than 53 kilometers from the plant were excluded from the analysis. Additionally, pursuant to the "20D Rule," facilities outside the SIA were also excluded from the inventory if the entire facility's emissions (expressed in tons per year) were less than 20 times the distance (expressed in kilometers) from the facility to the edge of the SIA. In applying the 20D Rule, facilities in close proximity to each other (within approximately 5 kilometers of each other) were considered as one source. Then, any Increment consumers from the provided inventory were added to the permit application forms or other readily available permitting information.

The regional source inventory used in the analysis is included in the permit application.

NAAQS Analysis

In the NAAQS analysis, impacts within the facility's SIA due to the potential emissions from all sources at the facility and those sources included in the regional inventory were calculated. Since the modeled ambient air concentrations only reflect impacts from industrial sources, a "background" concentration was added to the modeled concentrations prior to assessing compliance with the NAAQS.

The results of the NAAQS analysis are shown in Table 6-5. For the short-term averaging periods, the impacts are the highest second-high impacts. For the annual averaging period, the impacts are the highest impact. When the total impact at all significant receptors within the SIA are below the corresponding NAAQS, compliance is demonstrated.

Table 6-5: NAAQS Analysis Results

Pollutant	Averaging Period	Year	UTM East (km)	UTM North (km)	Maximum Impact (ug/m^3)	Background (ug/m^3)	Total Impact (ug/m^3)	NAAQS (ug/m^3)	Exceed NAAQS?
PM_{10}	24-hour	2002	772.9	348.2	52.24	38	90.24	150	No
	Annual	2005	772.9	348.3	19.65	20	39.65	50	No

Data for worst year provided only.

As indicated in Table 6-5 above, the total modeled impacts for PM_{10} at all significant receptors within the SIA are below the corresponding NAAQS.

Increment Analysis

The modeled impacts from the NAAQS run were evaluated to determine whether compliance with the Increment was demonstrated. The results are presented in Table 6-6.

Table 6-6: Increment Analysis Results

Pollutant	Averaging Period	Year	UTM East (km)	UTM North (km)	Maximum Impact (ug/m^3)	Increment (ug/m^3)	Exceed Increment?
PM_{10}	24-hour	2003	772.9	3482.3	18.18	30	No
	Annual	---	---	---	0.0	17	No

Data for worst year provided only

Table 6-6 demonstrates that the impacts are below the corresponding increments for PM_{10} for the 24-hour and annual averaging periods even with the conservative modeling assumption that all NAAQS sources were Increment sources.

Please refer to the EPD modeling memo dated November 9, 2009 included in Appendix C for details of the Increment Analysis.

Ambient Monitoring Requirements

Table 6-7: Significance Analysis Results – Comparison to Monitoring *De Minimis* Levels

Pollutant	Averaging Period	Year*	UTM East (km)	UTM North (km)	Monitoring De Minimis Level (ug/m^3)	Modeled Maximum Impact (ug/m^3)	Significant?
PM_{10}	24-hour	2002	772.9	3482.3	10	56.55	**Yes**
CO	8-hour	2004	772.0	3481.6	575	40.24	No

Data for worst year provided only

Please refer to the EPD modeling memo dated November 9, 2009 included in Appendix C for details of the preconstruction monitoring evaluation.

The impacts for CO and PM_{10} quantified in Table 6-4 of the Class II Significance Analysis are compared to the Monitoring *de minimis* concentrations, shown in Table 6-1, to determine if ambient monitoring requirements need to be considered as part of this permit action.

As shown in the above Table 6-7, predicted concentrations of CO are below their respective monitoring de minimus threshold values and therefore no pre-construction monitoring is required for this pollutant. But that is not the case for PM_{10}, which showed predicted concentrations that exceed the monitoring de minimis levels; hence preconstruction monitoring would be necessary for PM_{10}.

In lieu of such monitoring effort, existing ambient air data from a representative regional monitoring station can be used. Such stations are for PM_{10}, station 130950007 located in Albany, GA approximately nine miles north from the permitted facility.
Being operated by GA EPD, the data from this monitoring station can be considered as contemporaneous, representative, and fulfilling all the QA/QC requirements.

As noted previously, the VOC *de minimis* concentration is mass-based (100 tpy) rather than ambient concentration-based (ppm or $\mu g/m^3$). Projected VOC emissions increases resulting from the proposed modification exceed 100 tpy; however, the current Georgia EPD ozone monitoring network (which includes monitors in Leslie, Georgia) will provide sufficient ozone data such that no pre-construction or post-construction ozone monitoring is necessary.

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 300 kilometers has been used for all facilities.

The four Class I areas within approximately 300 kilometers of Plant Mitchell are;

- The Okefenokee Swamp National Wildlife Refuge in Georgia, located approximately 160 kilometers southeast of the facility,
- The Wolf Island National Wildlife Refuge in Georgia, located approximately 267 kilometers east of the facility,
- The St. Marks National Wildlife Refuge in Florida, located approximately 155 kilometers south of the facility, and
- The Bradwell Bay Wilderness Area in Florida located approximately 149 kilometers south-southwest of the facility.

The U.S. Fish and Wildlife Service (FWS) is the designated Federal Land Manager (FLM) responsible for oversight of the first three of these Class I areas and the Forest Service (FS) is the designated FLM for Bradwell Bay.

To determine whether this application is subject to a Class I modeling analysis, the Q/d factor was used, where "Q" is the sum of all SO_2, NOx, PM_{10} and sulfuric acid mist emissions in tons per year caused by the project, and "d" is the distance between the proposed source and the nearest Class I area boundary.

The total emissions of these pollutants for GA Power Plant Mitchell after the proposed modifications is –1391.6 tpy due to the reduction in the SO_2 and NOx emissions. The Q/d factor for all of the Class I areas is less than zero, and the screening threshold established by the FLMs to determine if a project is required to submit a Class I modeling analysis is Q/d = 10. Most results below this value are considered not to have a significant impact on the Class I Air Quality Related Values (AQRVs).

The FWS was notified of the conditions of this project and their response was that further analysis was not required. The FS on the other hand, had previously reached an agreement with GA EPD by which PSD applications with Q/d values less than 4 would not be required to be reviewed by them for AQRV compliance.

Notwithstanding the FLMs decisions regarding AQRVs, compliance with Class I SILs is still required. A Class I SIL screening analysis was conducted by GA EPD. AERMOD (version 07026) was used as a screening tool. Emissions of PM_{10} from the permitted facility was modeled with receptors located at 50 km downwind in direction to each of the Class I areas. This forms two archs of approximately 34 and 60 kilometers, which is the width of the extension of the clustered Saint Marks / Bradwell Bay areas, and

Okefenokee / Wolf Island areas, respectively. At this distance, the archs are formed with respect to their corresponding azimuths with Plant Mitchell (See Figure 1 in the Appendix of the EPD modeling memo dated November 9, 2009 included in Appendix C). Such receptor grids were 1 km spaced between adjacent points, and the maximum predicted concentrations are shown in Tables 6-8 through 6-11 for each of the previously mentioned Class I areas.

Results show that maximum predicted concentrations of all pollutants in all four Class I areas were below the SILs and therefore no further Class I PSD increment analysis is required.

TABLE 6-8. PROJECT IMPACTS VS. SIGNIFICANCE LEVELS (OKEFENOKEE CLASS I AREA)

Criteria Pollutant	Averaging Period	Significance Level	Maximum Predicted Concentration*	Receptor Location UTM Zone 1 6		Model Met Data Period
		(μg/m³)	(μg/m³)	X	Y	[yy,mm.dd,hh]
PM10	Annual	0.2	0.0	---	---	---
	24-Hour	0.3	0.047	815507	3457144	01081924

* Highest value.

TABLE 6-9. PROJECT IMPACTS VS. SIGNIFICANCE LEVELS (WOLF ISLAND CLASS I AREA)

Criteria Pollutant	Averaging Period	Significance Level	Maximum Predicted Concentration*	Receptor Location UTM Zone 16		Model Met Data Period
		(μg/m³)	(μg/m³)	X	Y	[yy,mm,dd,hh]
PM10	Annual	0.2	0.0	---	---	---
	24-Hour	0.3	0.051	822351	3484191	05052724

* Highest value.

TABLE 6-10. PROJECT IMPACTS VS. SIGNIFICANCE LEVELS (ST. MARKS CLASS I AREA)

Criteria Pollutant	Averaging Period	Significance Level	Maximum Predicted Concentration*	Receptor Location UTM Zone 16		Model Met Data Period
		(μg/m³)	(μg/m³)	X	Y	[yy,mm,dd,hh]
PM10	Annual	0.2	0.0	---	---	---
	24-Hour	0.3	0.059	777955	3432757	05111724

* Highest value.

TABLE 6-11. PROJECT IMPACTS VS. SIGNIFICANCE LEVELS (BRADWELL BAY CLASS I AREA)

Criteria Pollutant	Averaging Period	Significance Level	Maximum Predicted Concentration*	Receptor Location UTM Zone 16		Model Met Data Period
		(μg/m³)	(μg/m³)	X	Y	[yy,mm,dd,hh]
PM10	Annual	0.2	0.0	---	---	---
	24-Hour	0.3	0.068	753328	3436218	01121124

* Highest value.

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

With regard to the impacts on soils and vegetation, the criteria to assess air pollution impacts are the standards contained in the EPA document *"A Screening Procedure for the impacts of Air Pollution Sources on Plants, Soils, and Animals"*. There are no standards for PM_{10} in this document, and considering that NAAQS modeling results show that there is still a significant margin from the standards, it can be concluded that PM_{10} impacts on soils and vegetation would be negligible. The other pollutant subject to PSD review, CO, did not exceed the SILs and therefore the same conclusion would apply.

Growth

The growth analysis is a projection of the commercial, industrial, and residential growth that may be expected to occur as a direct result of the implementation of the proposed project. In the case of Plant Mitchell, the facility is expected to employ an average of 110 new workers during the construction phase of no more than two years. On a permanent basis, the number of workers at the plant will actually decrease due to there being less equipment needed for the biomass operation as opposed to the coal operation. New jobs are expected to be created in the area associated with the supply of biomass to the plant, but it is expected to be relatively small and dispersed over the whole region. Therefore, no significant related industrial, commercial or residential growth is expected to accompany this project, hence no growth-related air pollution impacts can be foreseen.

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, 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.

The primary variables that affect whether a plume is visible or not at a certain location are (1) quantity of emissions, (2) types of emissions, (3) relative location of source and observer, and (4) the background visibility range. For any exhaust plume visibility analysis, a Level-1 visibility analysis can be performed using the latest version of the EPA VISCREEN model according to the guidelines published in the *Workbook for Plume Visual Impact Screening and Analysis* (EPA-450/4-88-015). The VISCREEN model is designed specifically to determine whether a plume from a facility may be visible from a given vantage point. VISCREEN performs visibility calculations for two assumed plume-viewing backgrounds (horizon sky and a dark terrain object). The model assumes that the terrain object is perfectly black and located adjacent to the plume on the side of the centerline opposite the observer. GA EPD recommended that VISCREEN not be conducted as there are no sensitive receptors located in the maximum significant impact area.

Georgia Toxic Air Pollutant Modeling Analysis

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

Selection of Toxic Air Pollutants for Modeling

For projects with quantifiable increases in TAP emissions, an air dispersion modeling analysis is generally performed to demonstrate that off-property impacts are less than the established Acceptable Ambient Concentration (AAC) values. The TAP evaluated are restricted to those that may increase due to the proposed project. Thus, the TAP analysis would generally be an assessment of off-property impacts due to facility-wide emissions of any TAP emitted by a facility. To conduct a facility-wide TAP impact evaluation for any pollutant that could conceivably be emitted by the facility is impractical. A literature review would suggest that at least one molecule of hundreds of organic and inorganic chemical compounds could be emitted from the various combustion units. This is understandable given the nature of the biomass, distillate and biodiesel 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.

The permitted facility discharges to the atmosphere thirty nine hazardous air pollutants (HAPs) shown in Table IX of the EPD modeling memo dated November 9, 2009 included in Appendix C as emitted from the biomass boiler and the wood chipper. Emission rates were estimated using the AP-42 emission factors at the operating conditions (fuel load) that yield the worst emission rates.

Similar to the significant impact analysis, different operating conditions of the biomass boiler can result in different impacts on ambient air from the HAPs emissions. Therefore, the maximum, intermediate, and low fuel load with their corresponding exit temperature and velocities were modeled at unit emission rate ($1 g/m^3$), and then the Maximum Ground Level Concentrations (MGLCs) during the 5-year modeling period were scaled to its applicable emission rate for each pollutant.

The results show that the MGLCs at 24-hour and annual averaging periods occur at relative low fuel load with lower exhaust temperature and exit velocity, although with lower emission rates; whereas at the 15-min averaging period, the MGLCs occur at an intermediate fuel load.

Modeled concentrations were calculated for 1 year, 24 hours, and 1 hour averaging periods. The 1-hour results were converted to 15 minutes averages for further comparison with the corresponding Acceptable Ambient Concentration (AAC). The annual and 24-hour modeled values were compared directly to their corresponding AAC.

The ISCST3 model (version 02035) was used for this analysis, and the AACs were calculated for each one of those substances and their applicable time-averaging periods according to EPD's Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions. Comparison shows that all MGLCs assessed were found to be less than their respective AACs, as presented in Table IX of the EPD modeling memo dated November 9, 2009 included in Appendix C.

Assessment of Silver Emissions

In addition to the compounds originally examined, EPD investigated silver emissions from wood combustion in regard to Georgia's Toxic Guideline. While silver is not a listed HAP, the AP-42 emission factor, coupled with a fairly low OSHA TWA value of 0.01 mg/m3 prompted further study. Upon review of the background of the AP-42 emission factor for silver, and comparison with other test data, EPD determined that the emission factor of 1.4E-4 lb/MMBtu provided by NCASI is likely more accurate than AP-42. GA EPD concluded that silver emissions are not significant, and the modeling results have been added in the amended Table IX of Appendix C.

8.0 EXPLANATION OF DRAFT PERMIT CONDITIONS

The permit requirements for this proposed facility are included in draft Permit Amendment No. 4911-095-0002-V-02-3.

Section 1.0: Facility Description

The facility proposes to convert the 155 MW coal-fired steam generating unit (Source Code: SG03) to a 96 MW biomass-fired steam generating unit. The facility will add new biomass fuel handling, processing, storage, and delivery systems.

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 3.2.4 is added to replace the requirements pertaining to the previous coal-fired steam generating unit (Source Code: SG03) and add the biomass requirements for the modified biomass-fired steam generating unit. This condition defines the type of biomass or wood the facility can burn in this boiler.

New Condition 3.2.5 is added to require that the Multiclone (Source code: MC03) and the Dry ESP (Source Code: EP03) control devices for the steam generating unit (Source Code: SG03) are operated at all times that the steam generating unit (Source Code: SG03) is operating except during startup, shutdown, or malfunction.

New Condition 3.3.1 requires that the facility comply with the 40 CFR 60 New Source Performance Standards (NSPS), Subpart A "General Provisions" and 40 CFR 60 Subpart IIII "Standards of Performance for Stationary Compression Ignition Internal Combustion Engines", for the operation of the engine powering the wood chipping unit (Source Code: WC03).

New Condition 3.3.2 and new Condition 3.3.3 state that the operation of the steam generating unit (Source Code: SG03) is subject to the requirements of the New Source Performance Standards" as found in 40 CFR Part 60, Subpart A, "General Provisions" and 40 CFR 60, Subpart Db, "Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units".

New Condition 3.3.4 states the PSD requirement that the facility must commence construction of all units within 18 months of the date of issuance of this Permit.

New Condition 3.3.5 defines the minimum operational load and startup and shutdown load for the Steam Generating Unit (Source Code: SG03).

New Condition 3.3.6 requires Steam Generating Unit (Source Code: SG03) to operate at no less than the minimum operational load as defined in Condition 3.3.5.

New Condition 3.3.7 limits the workday for unpaved roadway sources associated with wood chipping operations to a 12-hour workday. The modeling of fugitive PM for this project reflects a 12-hour workday. In order to meet modeling requirements, this 12-hour workday becomes a BACT condition in the permit amendment.

New Conditions 3.3.8, 3.3.9, and 3.3.10 define the BACT limits for VOC, CO, and PM_{10}. The PM_{10} BACT limit in Condition 3.3.10 shall be applicable at all times including startup, shutdown or malfunction.

New Condition 3.3.11 defines the BACT control for the Biomass Handling System (Source Code: BHS).

New Condition 3.3.12 states the BACT requirement that only ultra-low sulfur diesel fuel is fired in the new Wood Chipping Unit (Source Code: WC03).

New Condition 3.3.13 is added to set the operating BACT limit for new Wood Chipping Unit (Source Code: WC03) to 3000 hrs per any 12 consecutive months.
New Condition 3.4.6 states the Georgia State Rule 391-3-1-.02(2)(d)4(ii) requirement for NOx emissions from the Steam Generating Unit (Source Code: SG03).

New Condition 3.4.7 states the Georgia State Rule 391-3-1-.02(2)(g)2 requirement for sulfur emissions from the wood chipping unit (Source Code: WC03).

New Condition 3.4.8 states the Georgia State Rule 391-3-1-.02(2)(d)2(i) requirement for particulate matter emissions from the wood chipping unit (Source Code: WC03).

New Condition No. 3.4.9 replaces the references to the coal handling system (Source Code: CHS) with references to the biomass handling system (Source Code: BHS) since this system will replace the coal handling system (Source Code: CHS), and adds the wood chipping unit (Source Code: WC03). This condition states the Georgia State Rules 391-3-1-.02(2)(n)1 for preventing fugitive dust from becoming airborne.

New Condition No. 3.4.10 replaces the references to the coal handling system (Source Code: CHS) with references to the biomass handling system (Source Code: BHS) since this system will replace the coal handling system (Source Code: CHS), and adds the wood chipping unit (Source Code: WC03). This condition states the Georgia State Rule 391-3-1-.02(2)(n)2 requirement for 20% opacity.

<u>Section 4.0: Requirements for Testing</u>

Condition 4.1.3 was updated to include the general testing requirements for the steam generating unit (Source Code: SG03) and the wood chipping unit (Source Code: WC03).

New Condition 4.1.5 updates the section with the latest requirements for monitoring systems.

Condition 4.2.1 was modified to state the 180 days testing requirement to perform initial particulate matter test and update the reference to new Condition 3.3.10.

New Condition 4.2.2 states the particulate matter testing requirements to comply with NSPS Subpart Db as listed in Conditions 3.3.3 and the BACT limit in Condition 3.3.10.

New Condition 4.2.3 requires that performance evaluations for the CO CEMS monitoring device begin within 180 days after the steam generating unit (Source Code: SG03) startup.

New Condition 4.2.4 requires performance testing for hydrogen chloride, benzene, formaldehyde, acrolein and styrene from Steam Generating Unit (Source Code SG03) in order to provide data to help comply with the applicable MACT 112(j) standards.

New Condition 4.2.5 states the initial and annual performance testing requirements for VOC emissions from Steam Generating Unit (Source Code SG03).

Section 5.0: Requirements for Monitoring

Condition 5.2.1 has been modified to include the requirement for a CO CEMs and a NOx CEMs.

New Condition 5.2.10 states additional NSPS Subpart Db monitoring requirements for the voltage and amperage on the dry electrostatic precipitator for the steam generating unit (Source Code: SG03). Condition 5.2.10.c requires the facility to install a continuous monitor for gross electrical output.

New Condition 5.2.11 states the requirements to assess the quality and accuracy of the data acquired by the carbon monoxide CEMS.

New Condition 5.2.12 states the requirements for obtaining CO emissions data.

New Condition 5.2.13 requires submission of a CAM plan no later than 180 days after initial startup of the facility.

New Condition 5.2.14 requires the installation, calibration and operation of a non-resettable continuous monitoring system (or device) to track the hours of operation of the wood chipping unit (Source Code: WC03)

New Condition 5.2.15 replaces the requirements of daily coal sampling with the requirements for monthly monitoring of the biomass fired.

New Condition 5.2.16 replaces the used oil sampling requirements with certification and sampling requirements for ultra low sulfur fuel oil, biodiesel blend, and biomass fuels.

Section 6.0: Other Recordkeeping and Reporting Requirements

Condition 6.1.7 is updated to provide general reporting requirements for the steam generating unit (Source Code: SG03).

New Condition 6.2.8 states the recordkeeping requirements for periods such as startup, shutdown, malfunction or inoperation of the steam generating unit (Source Code: SG03) and the wood chipping unit (Source Code: WC03).

New Condition 6.2.9 states the quarterly reporting requirements for the steam generating unit (Source Code: SG03) and the wood chipping unit (Source Code: WC03).

New Condition 6.2.10 states the method for determining and recording total secondary power for each field of the electrostatic precipitator (Source Code: EP03).

New Condition 6.2.11 states the notification requirements for initial startup of the steam generating unit (Source Code: SG03) and the wood chipping unit (Source Code: WC03).

New Condition 6.2.12 states the recordkeeping requirements for startup of the steam generating unit (Source Code: SG03) and the wood chipping unit (Source Code: WC03).

New Condition 6.2.13 states the method for determining and recording CO CEMS data to show compliance with the CO limit in Condition No. 3.3.9.

New Conditions 6.2.14 and 6.2.15 state the method for determining, recording and reporting wood chipping unit (Source Code: WC03) operating data to show compliance with the operating hour limits in Condition Nos. 3.3.7 and 3.3.13.

New Condition 6.2.16 removes the references to coal, sawdust, used oil, and coal-derived synthetic fuel and replaces with biomass, and biodiesel fuels in the recordkeeping requirements. Ultra low sulfur oil was added to the list of fuel oils.

New Condition 6.2.17 removes the references to coal and sawdust and replaces with biomass for representative samples and required recordkeeping.

New Condition 6.2.18 removes the references to the coal handling system (Source Code: CHS) and replaces with the biomass handling system (Source Code: BHS) and add the wood chipping unit (Source Code: WC03) for fugitive dust suppression records.

New Condition 6.2.19 provides a requirement for supplier certification that the engine of the wood chipping unit (Source Code: WC03) meets NSPS Subpart IIII requirements.

Section 7.0: Other Specific Requirements

New Condition 7.14.1 states the PSD requirement that the permit is null and void if the construction of the wood-fired Steam Generating Unit (Source Code: SG03) is not commenced with eighteen months of the effective date of this amendment.

New Condition 7.14.2 states that upon completion of this project, Condition Nos. 3.2.1, 3.2.2, 3.4.1, 3.4.4, 3.4.5, 5.2.2, 5.2.3, 6.2.1, 6.2.2, 6.2.5 and 6.2.6 will no longer be applicable.

APPENDIX A

Draft Revised Title V Operating Permit Amendment
Mitchell Steam-Electric Generating Plant
Albany (Dougherty County), Georgia

APPENDIX B

Mitchell Steam-Electric Generating Plant PSD Permit Application and Supporting Data

Contents Include:

1. PSD Permit Application No. 18663, dated December 18, 2008-Public copy available at http://www.georgiaair.org/airpermit/html/permits/psd/main.html.
2. Additional Information Package Received April 20, 2009 (February 01, 2008 Fuel Analysis)
3. Additional Information Package Received May 29, 2009 (Response to May 21, 2009 Questions and Cost Analysis Spreadsheet)
4. Additional Information Package Dated November 12, 2009 (Response to EPA Region IV comments)
5. Evaluation of Silver Emissions for the Mitchell Biomass Project, dated February 5, 2010

APPENDIX C

EPD'S PSD Dispersion Modeling and Air Assessment Review

APPENDIX D

BACT Analysis Spreadsheets