Prevention of Significant Air Quality Deterioration and Nonattainment New Source Review Review Of Georgia Power Company Plant McDonough Combined-Cycle Electric Generating Units Located in Smyrna, Cobb County, Georgia

PRELIMINARY DETERMINATION
SIP Permit Application No. 17297
November 2007

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

Stationary Source Permitting Program (SSPP)
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SUMMARY

The Environmental Protection Division (EPD) has reviewed the application submitted by Georgia Power Company Plant McDonough for a permit to construct three combined-cycle electric generating blocks. Each combined-cycle block will be nominally rated at 840 MW and will include two combustion turbines (CTs) each with a supplementally fired (duct burner) heat recovery steam generator (HRSG) and associated support facilities. The CTs will fire pipeline quality natural gas as the primary fuel. Two CTs, one from each of two combined-cycle blocks, will also be able to fire ultra low sulfur (0.0015% S) distillate oil as a backup fuel. Each duct burner (maximum heat input of up to 650 MMBtu/hr), will fire only natural gas and/or landfill gas. Currently, Georgia Power also plans to construct three auxiliary boilers nominally rated at 200 MMBtu/hr, one for each combined-cycle block, in order to heat critical components during startup. The auxiliary boilers will fire only natural gas and/or propane-air.

Construction and operation of the new combined-cycle units is closely tied to the permanent shutdown of the two existing coal-fired units at Plant McDonough. The project will be constructed in two phases. In Phase I, Georgia Power will retire McDonough Unit 2 during the fourth quarter of 2010 and begin commercial operation of the first two combined-cycle blocks (blocks 4 & 5) in the first quarter of 2011 and the second quarter of 2011, respectively. In Phase II, the company will retire McDonough Unit 1 during the fourth quarter of 2011 and begin commercial operation of the third combined-cycle block (block 6) in the second quarter of 2012.

Each phase of the project will result in a net decrease in the emissions of nitrogen oxides (NO_x), sulfur dioxides (SO_2), particulate matter (PM / PM_{10}), sulfuric acid mist (H_2SO_4), fluorides, and lead, but will result in a net increase in the emissions of carbon monoxide (CO) and volatile organic compounds (VOC). The increases in emissions for the combined project will be greater than the applicable significance (for CO) or de minimus (for VOC) levels.

Georgia Power Company Plant McDonough is located in Cobb County, which is one of the 13 counties formerly designated as non-attainment for ground level ozone in the Atlanta Metro Area under the U.S. EPA one-hour standard. Under Georgia Air Quality Rule 391-3-1-.03(8)(c)(13)(i), the major source threshold for VOC and NOx (ground level ozone precursors) for sources in Cobb County is 25 tons per year (tpy). While the one-hour standard is no longer in effect, the more stringent one-hour standard NSR requirements remain in effect in the former one-hour ozone non-attainment counties, including Cobb County. Cobb County also lies within the boundaries of the eight-hour ozone Atlanta Non-Attainment Area and the PM2.5 Atlanta Non-Attainment Area.

The EPD review of the data submitted by Georgia Power 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 EPD that the proposed project provides for the application of Best Available Control Technology (BACT) for the control of CO as required by 40 CFR 52.21(j) and 391-3-1-.02(7), and for the application of the Lowest Achievable Emission Rate (LAER) for the control of VOCs as required by 391-3-1-.03(8)(c). With the contemporaneous emissions decreases resulting from the permanent shut downs of the two existing coal-fired units, the project will net out of PSD and NAA-NSR for all other regulated NSR pollutants.

To satisfy the emission offset requirement of Georgia Rule 391-3-1-.03(8)(c), Georgia Power must ensure that the project achieves a ratio of total emission reductions of VOCs to total emission increases of VOCs at least equal to 1.3 to 1. This requirement ensures a net reduction in the non-attainment pollutant of concern (in this case, VOCs).

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. Because CO is not a pollutant that can cause impairment of visibility, it was not

necessary to evaluate potential impacts in Class I areas. 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 Georgia Power Company Plant McDonough for the modifications necessary to construct three combined-cycle electric generating blocks. As required by state and federal permitting regulations (Title V and NSR), conditions are incorporated into the proposed permit to assure compliance with all applicable air quality regulations. A copy of the draft permit amendment is included in Appendix A.

1.0 INTRODUCTION

On March 8, 2007, Georgia Power Company Plant McDonough (hereafter Georgia Power) submitted an application for an air quality permit to construct three combined-cycle electric generating blocks with a supplementally fired (by duct burner) heat recovery steam generator (CT/HRSG) and associated support facilities at Plant McDonough, located at 5551 South Cobb Drive, Smyrna, Georgia 30080 (Cobb County). The permit application includes a description of the plant process operations, calculations of emission rates for each affected emissions unit, emission factors and process rates used to estimate potential emissions, a regulatory analysis, and Best Available Control Technology (BACT) / Lowest Achievable Emissions Rate (LAER) analyses. On July 25, 2007, Georgia Power submitted revised air quality modeling analyses to support the permit application. On October 10, 2007, Georgia Power submitted additional modeling analyses related to the startup of two combustion turbines on oil, in response to questions from EPD.

Major stationary sources of air pollution are required by the Clean Air Act to obtain a permit before commencing construction of permanent facilities or major modifications of permanent facilities. For PSD purposes, Plant McDonough is a major stationary source of PM, PM_{10}, SO_2, NO_x, and CO because its potential emissions of each of these regulated NSR pollutants exceed 100 tpy. Plant McDonough is also a major stationary source of VOCs and NO_x for NAA-NSR purposes because its potential emissions of each of these non-attainment pollutants exceeds 25 tpy. As a major source, any project at Plant McDonough that results in a significant emissions increase of any regulated PSD pollutant or a significant net emissions increase in any NAA NSR pollutant over the contemporaneous 5-year period, triggers the applicable major NSR for that pollutant.

Plant McDonough is located in Cobb County, which is within the Atlanta ozone non-attainment area and fine particulate ($PM_{2.5}$) non-attainment area, but is in attainment for all other criteria pollutants. As such, the NAA-NSR significance thresholds apply for emissions increases of VOCs and NO_x. On the other hand, PSD significance thresholds apply for emissions increases for all regulated NSR pollutants except NO_x and VOC. The EPA and EPD have not yet finalized major NSR requirements for $PM_{2.5}$. Therefore, in accordance with EPA’s 1997 and 2005 policy memoranda regarding $PM_{2.5}$, major source NSR for PM_{10} serves as a surrogate for major NSR for $PM_{2.5}$.

Comparing the project’s total potential to emit each of the regulated NSR pollutants to the applicable significance and de minimus thresholds, the new combined-cycle electric generating units will result in a possible significant emissions increase in PM, PM10, and CO and possible emissions greater than the de minimus level for NOx and VOC. Because the proposed modification is a phased construction project, with construction commencing on two units in 2008 and the third in 2010, emissions increases are evaluated separately for each phase of the project, in accordance with EPA guidance. Table 1-1 summarizes the emissions increases from each phase of the project and identifies which emissions increases will be possibly significant or greater than the de minimus level for each phase:

Table 1-1: Emissions Increases from the Project

Pollutant	Applicable Significance or De Minimus Threshold (TPY)	Phase I				Phase II	
		Block 4 PTE	Block 5 PTE	Total for Blocks 4 and 5	Possible Significant or De Minimus Emissions Increase?	Block 6 PTE	Possible Significant or De Minimus Emissions Increase?
SO_2	40	19.3	19.3	38.6	No	18.4	No
PM	25	202.7	202.1	404.8	**Yes**	174.7	**Yes**
PM_{10}	15	202.7	202.1	404.8	**Yes**	174.7	**Yes**
H_2SO_4	7	0.25	0.25	0.50	No	0.23	No
Fluorides	3	0	0	0	No	0	No
Pb	0.6	0.029	0.029	0.058	No	0.012	No
CO	100	261.1	261.1	522.1	**Yes**	240.7	**Yes**
VOC	25	135.1	135.1	270.2	**Yes**	131.6	**Yes**
NO_x (O_3)	25	216.7	216.7	433.4	**Yes**	199.5	**Yes**
NO_x (NO_2)	40	216.7	216.7	433.4	**Yes**	199.5	**Yes**

In determining if a modification triggers PSD or NAA-NSR, a source may also take into account all contemporaneous and creditable emissions increases and decreases. An increase or decrease in actual emissions is contemporaneous with the increase resulting from a modification only if it occurs between (a) the date five years before construction on the modification commences, and (b) the date that the increase from the modification occurs. Georgia Power currently plans to commence construction on Blocks 4 & 5 (Phase I) in May 2008 and August 2008, respectively. Construction is currently projected to commence on Block 6 (Phase II) in February 2010. Georgia Power anticipates the startup of the first two combined-cycle units in the first and second quarters of 2011, and plans to startup the third combined-cycle unit in the second quarter of 2012.

Since Georgia Power anticipates commencing construction on the first two combined-cycle units in May of 2008, the contemporaneous period will begin in May of 2003 and end with the startup of the units. For the third combined-cycle unit, on which Georgia Power anticipates commencing construction in February of 2010, the contemporaneous period will begin in February of 2005 and end with the startup of the unit.

Table 1-2 outlines the net emissions changes resulting from each phase of the project, taking into account all contemporaneous and creditable emissions increases and decreases, including the permanent shutdown of the two existing coal-fired electric generating units. The emissions from the two existing coal-fired electric generating units is from the 24-month period from November 2004 to October 2006.

Table 1-2: NSR Applicability Analysis

Pollutant	Threshold TPY	Phase I			Phase II			Project Total	
		Blocks 4 & 5[2] TPY	Coal Unit 2 TPY	Phase I TPY	Block 6[3] TPY	Coal Unit 1 TPY	Phase II TPY	Net TPY	BACT or LAER?
SO_2	40	38.6	-13994.6	-13956.0	18.4	-13938.0	-13919.6	-27875.6	NO
PM	25	405.4	-1152.9	-747.5	174.7	-1149.1	-974.4	-1721.9	NO
PM_{10}	15	405.4	-974.9	-596.5	174.7	-971.7	-797.0	-1393.5	NO
H_2SO_4	7	0.5	-76.3	-75.8	0.23	-83.0	-82.8	-158.6	NO
Fluorides	3	0.0	-51.9	-51.9	0.0	-57.0	-57.0	-108.9	NO
Pb	0.6	0.058	-0.100	-0.042	0.012	-0.100	-0.088	-0.13	NO
CO	100	522.1	-178.9	343.2	240.7	-178.2	62.5	405.7	**BACT**
VOC	25	270.2	-21.5	248.7	131.6	-21.4	110.2	358.9	**LAER**
NO_x (O_3)	25	433.4	-2208.9	-1775.5	199.5	-2201.2	-2001.7	-3777.2	NO
NO_x (NO_2)	40	433.4	-2208.9	-1775.5	199.5	-2201.2	-2001.7	-3777.2	NO

Notes

1. For netting analysis details, see Chapter 3 of the air permit application.
2. Includes two new auxiliary boilers, a new cooling tower (Unit 4), two proposed cooling towers (scheduled to be completed in 2008), and oil storage tanks.
3. Includes one new auxiliary boiler.

For the McDonough Combined-Cycle Generating Units, a worst-case emission rate during normal operation was established for each pollutant and equipment type based on vendor data and other considerations, consistent with the proposed control choices. The highest lb/MMBtu emission rate identified for each pollutant was multiplied times the maximum heat input (MMBtu/hr) for each equipment type (combustion turbine and duct burner) to establish worst case, normal operation lb/hr rates. Two combustion turbines (one each from two of the combined-cycle blocks) will each have the capability of burning ultra low sulfur oil up to a limit of 1000 hours per year. The maximum emission rates during normal operation for each equipment type are summarized in Tables 2-1, 2-2, and 2-3 in Chapter 2 of the air permit application attached as Appendix B.

For certain pollutants, emission levels during startup can be higher than emission levels at normal operating conditions. This is due to the lower combustion efficiency at these low loads when the turbine is just beginning to heat up and due to the catalyst-based controls (SCR and catalytic oxidation) not yet reaching their optimum operating temperature (i.e., little or no catalyst benefit is available). To establish reasonable maximum annual emissions estimates for NO_x, CO, and VOC, cumulative emissions of each of these pollutants during startup and shutdown were calculated using vendor emission curves and sequencing for each startup type (i.e., cold, warm, and hot), including the length of time necessary for each type of startup, and for shutdown. Then an upper-end estimate was made of the average number and type of starts that might be experienced annually across all units. The startup emissions estimate also includes the use of the auxiliary boilers to heat critical components during each start. An estimate of the amount of down-time prior to each startup type was also assumed and a total downtime estimate was calculated.

The sum of total startup time and total down-time prior to startup was subtracted from available operating hours to determine the total annual operating time at normal conditions. Emissions at normal conditions were calculated assuming the worst case, normal operation lb/hr rate for the time available to operate at normal conditions. Startup/shutdown emissions estimates were combined with normal operation emissions to arrive at an estimate of the maximum annual emissions for NO_x, CO, and VOC with startup and shutdown explicitly included (see Table 2-4 in Chapter 2 of the air permit application). For all other pollutants the maximum annual emissions assumes operation at the worst case, normal operation emission rate for the entire year. Details of these calculations are provided in Chapter 2 of the air permit application.

The particulate matter emissions calculations include both filterable and condensable particulate from the units analyzed, including the combustion turbines (assuming 1,000 hours of oil firing from each of CT4A and CT5A), the cooling towers, and the existing coal-fired units, and also include the maximum ammonia sulfate created by reaction of ammonia slip and H_2SO_4. VOC emissions totals include emissions from the oil storage tanks. Hazardous air pollutant (HAP) emissions are detailed in Chapter 2 of the air permit application Tables 2-6 and 2-7.

The emission reductions associated with the retirement of the two coal-fired units satisfy all of the applicable criteria for being both contemporaneous and creditable and are thus acceptable for netting purposes. The details of the netting analyses are provided in Chapter 3 of the air permit application.

Therefore, the construction of the combined-cycle generating units at Plant McDonough will be subject to PSD review for CO emissions and NAA-NSR for VOC emissions. The project will employ an emissions control scheme meeting the standards of LAER for VOCs and BACT for CO. VOC emissions offsets, at a 1.3 to 1 ratio, are required prior to startup of the combined-cycle units. The air quality permit application confirms that the Applicant has procured these offsets. Because Georgia Power will shut down the two existing coal-fired units at the site in conjunction with operation of the new units, the project will net out of PSD and NAA-NSR for all other regulated NSR pollutants.

Through its new source review procedures, EPD has evaluated the proposed construction of three new combined-cycle electric generating units at Plant McDonough for compliance with State and Federal requirements. The findings of EPD are assembled in this Preliminary Determination.

2.0 PROCESS DESCRIPTION

According to Application No. 17297, Georgia Power has proposed to construct three combined-cycle electric generating blocks. Each combined-cycle block will include two combustion turbines each with a supplementally fired (duct burner) heat recovery steam generator (CT/HRSG) and associated support facilities. The two CT/HRSGs will supply steam to a single steam turbine. This arrangement of equipment is referred to as a two-on-one configuration. The nominal size of each of the combined-cycle blocks will be 840 MW.

For each of the three blocks, two Mitsubishi Heavy Industries, LTD (MHI) Model M501G, 250 MW combustion turbines (CTs) will be used and will fire pipeline quality natural gas as the primary fuel. Two CTs, one from each of two combined-cycle blocks, will also have the capability to fire ultra low sulfur diesel fuel (0.0015 weight percent sulfur) as a backup fuel. Each duct burner (maximum heat input of 650 MMBtu/hr based on Application 17297, but smaller duct burners may be selected), will fire only natural gas and landfill gas. The steam turbine will generate approximately 340 MW of electric power. The CT/HRSG units will be capable of continuous operation at baseload for up to 8,760 hours per year while firing natural gas. The two combustion turbines capable of burning ultra low sulfur oil will each be limited to 1,000 hours per year of distillate fuel oil usage. Georgia Power also plans to construct three auxiliary boilers nominally rated at 200 MMBtu/hr, one for each combined-cycle block, in order to heat critical components during startup.

Construction and operation of the new combined-cycle units is closely tied to the permanent shutdown of the two existing coal-fired units. Georgia Power will retire McDonough Unit 2 during the fourth quarter of 2010 and begin commercial operation of the first two combined-cycle blocks (Blocks 4 & 5) in the first quarter of 2011 and the second quarter of 2011, respectively. Georgia Power will retire McDonough Unit 1 during the fourth quarter of 2011 and begin commercial operation of the third combined-cycle block (Block 6) in the second quarter of 2012.

Each combustion turbine will be equipped with a dry low-NOx combustor. The two combustion turbines designed to fire ultra low sulfur fuel oil will also be equipped with water injection to minimize NOx production. Each duct burner will be equipped with low-NOx burners. Selective catalytic reduction equipment will be used to control NOx emissions from the combined exhaust of the turbine and its paired duct burner. Emissions of SO2 from the combined-cycle units will be minimized by restricting fuel use to natural gas, landfill gas, and ultra low sulfur diesel fuel. Emissions of CO and VOC will be controlled by good combustion practices and the use of post-combustion catalytic oxidation equipment. The use of clean, low-ash fuels and good combustion practices will limit the emissions of particulate matter. These controls will allow Plant McDonough combined-cycle electric generating units to achieve emission levels well below applicable emission limits.

The ultra low sulfur oil will be stored in two existing above-ground tanks or two new above ground tanks. A new cooling tower will be constructed to support operation of the first combined-cycle block. Two cooling towers are currently under construction and expected to go into service no later than June 2008 to support the existing coal-fired units. After retirement of the first coal-fired unit (McDonough Unit 2), one of the existing cooling towers will be reconfigured to support operation of the second combined-cycle block. After retirement of the second coal-fired unit (McDonough Unit 1), the second existing cooling tower will be reconfigured to support operation of the third combined-cycle block. All three of these cooling towers will include high-efficiency drift eliminators and plume abatement systems.

The Georgia Power 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 Rule (Georgia Rule) 391-3-1-.03(1), Construction Permit, 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).

Georgia Rule 391-3-1-.02(2)(b), Visible Emissions, limits the opacity of visible emissions from any air contaminant source which is subject to some other emission limitation under 391-3-1-.02(2). The opacity of visible emissions from regulated sources may not exceed 40 percent under this general visible emission standard. It is expected that the opacity of all emissions from the combined-cycle electric generating units and associated auxiliary and support equipment will be well below 40% at all times.

Georgia Rule 391-3-1-.02(2)(d) for Fuel-burning Equipment limits opacity, particulate matter (PM), and nitrogen oxides (NO_x) emissions from fuel-burning equipment. The allowable particulate matter emission rates are 0.10 lb/MMBtu for each duct burner. For each auxiliary boiler, the allowable particulate matter is based on an equation relating the heat input to the emission limit (0.11 lb/MMBtu at the design capacity of 200 MMBtu/hr). Secondly, this regulation limits visible emissions from each affected unit to no more than 20% opacity except for one 6-minute period in any hour of no more than 27% opacity. Thirdly, this rule also limits the allowable NO_x emission rates from each duct burner are 0.3 lb/MMBtu, when firing oil, and 0.2 lb/MMBtu, when firing gas.

Georgia Rule 391-3-1-.02(2)(g), Sulfur Dioxide, applies to all “fuel burning” sources. The “fuel burning” sources at the proposed site will include the combustion turbines, duct burners, and auxiliary boilers. The site may also include an emergency diesel firewater pump, which, if constructed, will be subject to this rule. Rule (g)1 applies to each combustion turbine and duct burner because each has an individual heat input capacity exceeding 250 MMBtu/hr and was constructed after January 1, 1972. Rule (g)2 applies to each “fuel burning” source at the proposed site. Sulfur dioxide emissions from each combustion turbine and from each duct burner shall not exceed 0.8 lbs/MMBtu of heat input derived from liquid fossil fuel in accordance with Rule 391-3-1-.02(2)(g)1. The fuel sulfur content limit for fuels burned in each combustion turbine, duct burner and auxiliary boiler is 3 percent sulfur by weight in accordance with Rule 391-3-1-.02(2)(g)2, which applies to each piece of equipment rated at 100 MMBtu/hr or greater. The fuel sulfur content limit for fuels burned in the firewater pump would be 2.5 percent by weight, in accordance with Rule (g)2, assuming it is rated lower than 100 MMBtu/hr.

Georgia Rule 391-3-1-.02(2)(tt), VOC Emissions from Major Sources, requires sources with potential emissions of VOC exceeding 25 tpy in Cobb County to apply Reasonably Available Control Technology (RACT) to reduce those VOC emissions. Because the new combined-cycle electric generating units at Plant McDonough will employ LAER for VOCs, including catalytic oxidation, the combined-cycle units will comply with Rule (tt). The new auxiliary boilers at Plant McDonough are limited to 175,200 MMBtu/yr (equivalent to 10% annual capacity factor) and will have potential VOC emissions of 1.33 tons per year, combined. Additional VOC controls, therefore, would not be cost effective so RACT is no control for the boilers.

Georgia Rule 391-3-1-.02(2)(yy), Emissions of Nitrogen Oxides from Major Sources, requires sources with potential emissions of NO_x exceeding 25 tpy in Cobb County to apply Reasonably Available Control Technology (RACT) to reduce those NO_x emissions. However, the rule also exempts individual equipment that is subject to subsections (jjj), (lll), (mmm), or (nnn). Because the auxiliary boilers will be subject to Rule (lll), and the combustion turbines will be subject to Rule (nnn), these units are exempt from Rule (yy). The duct burners associated with the new combined-cycle electric generating units at Plant McDonough are subject; they will employ low NO_x burner and selective catalytic reduction technology, and thus will be in compliance with Rule (yy).

Georgia Rule 391-3-1-.02(2)(lll), NO_x Emissions from Fuel-burning Equipment, establishes ozone-season NO_x emissions limits for fuel-burning equipment with a maximum heat input rate between 10 MMBtu/hr and 250 MMBtu/hr located in specified counties, including Cobb County. Because each auxiliary boiler has a rated heat input of 200 MMBtu/hr, this rule sets a NO_x limit for those units equal to 30 ppm at 3% oxygen during the period May 1 through September 30 of each year. This rule specifically exempts duct burners associated with combined-cycle gas turbines.

Georgia Rule 391-3-1-.02(2)(nnn), NO_x Emissions from Large Stationary Gas Turbines, establishes ozone-season NO_x emissions limits for large stationary gas turbines located in specified counties, including Cobb County. Upon unit startup, Rule (nnn) requires each of the new combustion turbines to emit no more than 6 ppm NO_x at 15% oxygen during the period May 1 through September 30 of each year. Each of the CT/HRSGs being installed with this project will include an SCR system that will reduce NO_x emissions to 2 ppm at 15% oxygen when firing natural gas and to 6 ppm at 15% oxygen when firing oil. Therefore, the new combustion turbines will satisfy the requirements of Rule (nnn).

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, and 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. BACT is defined 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 an enforceable emissions standard, it may require the source to use a design, equipment, work practice or operations standard or combination thereof, to reduce emissions of the pollutant to the maximum extent practicable.

The NSR Workshop Manual mentioned above includes the EPA 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 described in the NSR Workshop Manual in their 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.

Federal Rule – Nonattainment Area New Source Review

Georgia Rule 391-3-1-.03(8)(c) implements the State's Non-Attainment Area New Source Review (NAA-NSR) program. It applies to the proposed modification of an existing major source, located in a Non-Attainment Area, if the project is expected to result in both a significant emissions increase and a significant net emissions increase of a regulated nonattainment pollutant.

Because Cobb County is within the Atlanta non-attainment area for ozone and fine particulate ($PM_{2.5}$), a significant emissions increase and significant net emissions increase either of NO_x or VOCs (ozone precursors), or of PM_{10} (a surrogate for $PM_{2.5}$) would trigger NAA-NSR. The combined-cycle electric generating units will result in a net emissions decrease of NO_x and PM_{10}. However, the project will increase VOCs by a significant amount. Therefore, construction of the combined cycle electric generating units triggers NAA-NSR for VOCs.

Sources being permitted under these provisions are required to:

a. obtain offsetting emission reduction credits prior to startup;

b. comply with the LAER as determined using the RACT/BACT/LAER Clearinghouse (RBLC) and other authoritative sources;

c. certify that all other major stationary sources owned or operated by the Permittee are operating in compliance, or are on a schedule of compliance; and

d. submit an analysis of alternative sites, sizes, production processes and environmental control techniques for the proposed source to determine whether the benefits of the proposed source significantly outweigh the environmental and social costs imposed as the result of its proposed location, construction, or modification.

As discussed in more detail through the rest of this Preliminary Determination, Georgia Power has satisfied each of these requirements.

New Source Performance Standards

Subpart A (General Provisions)
Subpart A imposes generally applicable provisions for initial notifications, initial compliance testing, monitoring, and record keeping requirements. Since the new combined-cycle electric generating units and auxiliary boilers at Plant McDonough will be subject to one or more New Source Performance Standard, they will also be subject to Subpart A.

Subpart KKKK (Combined-cycle Combustion Turbines)
In the past, NO_x and SO_2 emissions from a CT operating with a HRSG and a duct burner (DB) were regulated by two separate standards of performance for stationary sources. Those emissions from the CT were subject to the limits imposed by Subpart GG of 40 CFR Part 60. On the other hand, those emissions from fuel-firing in either the HRSG or DB were subject to the NSPS limits in Subpart Da for electric utility steam generating units which commenced construction after September 18, 1978. However, on July 6, 2006, EPA promulgated Subpart KKKK governing emissions from combined-cycle combustion turbines (71 FR 38482). The applicability of that rule is similar to that of Subpart GG, except that Subpart KKKK applies to new, modified, and reconstructed stationary gas turbines, and their associated HRSGs and DBs. Subpart KKKK applies to all such affected facilities which commenced construction after February 18, 2005. Because the combined-cycle units of the proposed project are subject to Subpart KKKK, the applicable NSPS NO_x emissions limits for those units are as follows:

Subpart KKKK NO_x Limit:	
Firing natural gas	15 ppmv at 15% oxygen (0.43 lb/MWh)
Firing distillate oil	42 ppmv at 15% oxygen (1.3 lb/MWh)
HRSG/DB operating independent of CT	54 ppmv at 15% oxygen (0.86 lb/MWh)

Subpart KKKK also establishes an SO_2 emission standard equal to 0.90 lb/MWh. Alternatively, the source may choose to comply with the Subpart KKKK limit on fuel-sulfur content equal to 0.060 lb SO_2/MMBtu. This is approximately equivalent to a sulfur concentration in oil of 0.05 wt.% or 500 ppmw. Two of the proposed CTs will fire ultra low-sulfur diesel fuel (0.0015% S) as a backup fuel. This fuel will meet the Subpart KKKK limit for fuel-sulfur content. Also, all of the CT/HRSGs being installed with this project will include SCR systems that will meet the above Subpart KKKK NO_x limits.

Subpart Db (Industrial Steam Generating Unit)
Because each auxiliary boiler will burn only natural gas or propane-air, and will be limited by permit condition to no more than 175,200 MMBtu during any twelve consecutive months (equivalent to an annual capacity factor of 10%), those units will not be subject to Subpart Db performance standards for emissions of particulate matter, SO_2, or NO_x.

Subpart Kb (Volatile Organic Liquid Storage Vessel)
Subpart Kb applies to each storage vessel with a capacity greater than or equal to 75 cubic meters that is used to store volatile organic liquids on which construction, reconstruction, or modification is commenced after July 23, 1984. Georgia Power will use either the two existing 4 million gallon above-

ground storage tanks or new storage tanks for storing ultra low sulfur oil. Both the existing tanks and any new tanks would be exempt under 40 CFR 60.110b, which provides that Subpart Kb does not apply to tanks storing a liquid with a maximum true vapor pressure less than 3.5 kilopascals (2.175 psia), because ultra low sulfur diesel has a true vapor pressure of only 0.016 psia at 90 degrees F.

National Emissions Standards For Hazardous Air Pollutants

Plant McDonough is an existing major source of hazardous air pollutants. Major sources must comply with any applicable Maximum Achievable Control Technology (MACT) standards at MACT-affected units unless otherwise exempt. Even with the retirement of the existing coal units, the proposed combined-cycle project will still potentially be a major source of HAPs. The only MACT standard applicable to the combined-cycle combustion turbines is Subpart YYYY. However, this section of this Preliminary Determination also discusses Subpart DDDDD (for industrial boilers) and Subpart Q (for industrial process cooling towers).

Subpart A (General Provisions)
Subpart A imposes generally applicable requirements for initial notifications, initial compliance testing, monitoring, and record keeping requirements. Since two of the new combined-cycle electric generating units at Plant McDonough will be subject to one or more MACT standards, they will also be subject to Subpart A.

Subpart YYYY (Stationary Combustion Turbines)
EPA promulgated MACT standards for new stationary combustion turbines on March 5, 2004. These standards apply to stationary combustion turbines on which construction commenced after January 14, 2003. On April 7, 2004, however, EPA proposed to remove gas-fired units from the CT source category regulated by Subpart YYYY. In the interim, the Agency has stayed the applicability of Subpart YYYY requirements for gas-fired CTs.

Because four of the six CTs will be gas-fired only, the requirements of Subpart YYYY are stayed as applied to those units, although the Applicant must nevertheless comply with the Initial Notification requirements of 40 CFR 63.6145. If either of the two CTs that can fire oil (CT4A and CT5A) do so any time during a calendar year, when all CTs at the site burn oil for an aggregate of 1000 hours or more, then that CT will be classified as an oil-fired combustion turbine for that calendar year. Subpart YYYY limits formaldehyde emissions from a lean premix oil-fired stationary combustion turbine to 91 ppb at 15% oxygen when it is firing oil.

A catalytic oxidation system will be installed as LAER for VOC emissions from each of the six CT/HRSGs. For the two combustion turbines with oil-firing capability, their catalytic oxidation systems will also comply with the MACT standard for emissions of hazardous organic compounds. In particular, use of a catalytic oxidation system on each of those two units will meet the Subpart YYYY formaldehyde emission limit. To assure removal of HAPs, the 4-hour rolling average inlet temperature of the catalyst will be maintained within the range suggested by the catalyst manufacturer.

Subpart DDDDD (Industrial, Commercial, and Institutional Boilers and Process Heaters)
Subpart DDDDD was recently vacated by the U.S. Court of Appeals for the D.C. Circuit in Natural Res. Def. Council v. EPA, No. 04-1385, 2007 U.S. App. LEXIS 13388 (June 8, 2007).

Subpart DDDDD was promulgated September 13, 2004, for new industrial boilers, including those in the "large gaseous fuel subcategory" and the "large liquid fuel subcategory." The term "large" in that regulation was defined as a rated heat input capacity of greater than 10 MMBtu/hr. In addition to being "large," an industrial boiler in either of these subcategories was to have an annual capacity factor in excess of 10 percent. None of the proposed auxiliary boilers will have an annual capacity factor of greater than 10 percent. Thus, the auxiliary boilers would not have been subject to Subpart DDDDD, as it was issued.

The proposed duct burners would also not have been subject to these standards. Subpart DDDDD was not applicable to an electric utility steam generating unit, which is defined as a "fossil fuel-fired steam generating unit of more than 25 megawatts that serves a generator that produces electricity for sale." (69 FR 55220; Sept. 13, 2004) Each of the duct burners satisfies that definition.

Subpart Q (Industrial Process Cooling Towers (IPCTs))
In the preamble to this final rule, EPA concluded that Subpart Q should not apply to those IPCTs that are not operated with chromium-based water treatment chemicals because those IPCTs do not emit chromium compounds [see 59 FR 46345]. The electric utility industry is a major user of IPCTs which do not use chromium-based water treatment chemicals [see EPA, Chromium Emissions from Industrial Process Cooling Towers -- Background Information for Proposed Standards, 3-1 (Aug. 1993)]. Consequently, Subpart Q will not apply to the cooling towers at the McDonough Combined-Cycle Facility.

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 combined-cycle electric generating blocks associated with the proposed project would most likely result from a malfunction of the associated control equipment. While the facility will be required to carry out maintenance to assure good operation, the facility cannot anticipate or predict all malfunctions. However, the facility is required to minimize emissions during periods of startup, shutdown, and malfunction.

Federal Rule – 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, along with the Title V application. The CAM Plans are to 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 combustion turbines, which employ catalytic oxidizers to control carbon monoxide and volatile organic compounds and selective catalytic reduction units to control nitrogen oxides.

For CO and VOC, Georgia Power will monitor the concentration of CO and oxygen in the exhaust to the atmosphere. This approach provides a direct measurement for the CO permit limitation and an indirect assurance that the VOC emissions are within their permitted limitation, since the generation and removal of these pollutants are related. See Section 4.0 of this Preliminary Determination for an explanation of how the CO and VOC emissions are related. For NOx, Georgia Power will monitor the concentration of NOx and oxygen in the exhaust to the atmosphere. This approach provides a direct measurement for the NOx permit limitation. Based on this analysis, Georgia Power has submitted a CAM Plan that describes the general and performance criteria for one performance indicator for CO and VOC, which is the CO concentration in the atmospheric exhaust, and one performance indicator for NOx, which is the NOx concentration in the atmospheric exhaust. The CAM Plan appears in Part 5.2 of the Permit Amendment.

Federal Rules – Acid Rain Program

The Acid Rain regulations apply to the proposed combined-cycle electric generating units because they each have a nameplate capacity greater than 25 MW and they are to supply electricity for sale, whether wholesale or retail.

Federal Rules – Clean Air Interstate Rule (CAIR)

The Clean Air Interstate Rule regulations apply to the proposed combined-cycle electric generating units because they each have a nameplate capacity greater than 25 MW and they are to supply electricity for sale, whether wholesale or retail. Compliance with this new regulatory program will begin in 2009. Permit conditions will be added at a later date.

4.0 CONTROL TECHNOLOGY REVIEW

Each of the three combined-cycle blocks at Plant McDonough will include two combustion turbines, each with a supplementally fired (duct burner) heat recovery steam generator (CT/HRSG) and associated support facilities. As a result of this project, net emissions of CO will increase by a significant amount and the increase in VOC is above the de minimis level. Therefore, an emissions control scheme meeting the standards of LAER for VOCs and BACT for CO will be imposed on the facility.

LAER Technical Approach
The definition of LAER for any source means:

- The most stringent emissions limitation contained in the implementation plan of any State for such class or category of source; or

- The most stringent emissions limitation achieved in practice by such class or category of source.

BACT Technical Approach
Georgia Air Quality Control Regulation 391-3-1.02(7) incorporates the federal BACT requirements, including the definition of BACT, by reference. The regulations provide that "a major modification shall apply best available control technology for each regulated NSR pollutant for which it would result in a significant net emissions increase at the source." Best Available Control Technology (BACT) is defined as "an emissions limitation … based on the maximum degree of reduction for each pollutant subject to regulation under the Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable..." [40 CFR 52.21(b)].

Potentially available and applicable control options must first be identified. These technologies include those considered currently demonstrated on similar sources, which could be transferred to this project's type of equipment. The primary data sources used to identify candidate control technologies are:

- RACT/BACT/LAER Clearinghouse (RBLC)

- Combustion turbine vendor data

- Emission control equipment manufacturers

- Utility associations

These sources were investigated to determine the potential CO control technologies available, to develop the necessary data to determine achievable control levels, and to determine if the technologies can be employed in the proposed new equipment. Where appropriate, the control options for each pollutant were ranked by control level and evaluated considering energy impacts, environmental impacts, economic impacts, and other costs. Other considerations were also evaluated as appropriate.

The final step was to select the proposed BACT control level for CO considering all impacts.

Potential Control Options
The emissions controls available for CO and VOC are essentially the same. The formation of CO and VOC both result from incomplete combustion. Only three applicable CO and VOC control technologies have been identified for combustion turbines: (1) catalytic oxidation, (2) thermal oxidation, and (3) efficient combustion (good combustion practices). Catalytic oxidation is a post-combustion CO and VOC reduction technique. Efficient combustion is a direct result of the design and operation of the combustion turbine, including a proper air-to-fuel ratio and a design that adequately accounts for time, temperature,

and turbulence conditions within the combustion zone. These control options are explained in more detail below.

According to Georgia Power, post-combustion control of CO by thermal afterburning (thermal oxidation) has not received serious attention due to the significant fuel cost and the minor improvements in CO emissions to be gained by its use while increasing NO_x emissions. The fuel penalty for thermal afterburning is about 20 percent to accomplish an 80-percent reduction in CO while increasing NO_x by 18 to 50 ppm (depending on afterburner firing rate, fuel, and residence time). Also, a separate chamber would probably be required, which would add to the cost and backpressure. There is some reason to believe that the duct burner being installed on this combined-cycle may also produce some level of afterburner effect that could result in reduced CO and VOC emissions. However, current documentation to confirm this possibility is insufficient and, therefore, no credit was given to this possibility in the control technology analysis. The Division concurs with this assessment.

<u>Catalytic Oxidation</u>
Catalytic oxidation has been applied to reduce CO emissions from combustion turbines. Because the applicant and EPD are unaware of any other viable post-combustion CO control technology, catalytic oxidation was the only post-combustion control technology investigated.

Georgia Power describes catalytic oxidation systems in Section 5.0 of their permit application. With catalytic oxidation, the exhaust gases pass through a catalyst bed, typically platinum/rhodium, where oxidation of CO to CO_2 takes place. Depending on catalyst formulation, the reaction can occur over a temperature range of approximately 550 to 1200°F. The most efficient CO oxidation temperature will vary not only with catalyst type but also with contaminants in the gas stream. Hydrocarbons (VOC) present in the exhaust gases are also oxidized (to a lesser extent at optimum CO oxidation temperatures) to CO_2 and water vapor.

The amount of CO oxidation (or conversion) will depend on several factors, including temperature, space velocity, inlet CO, H_2O and SO_2 concentrations, and catalyst fouling. CO conversion temperatures are suitable for siting of the catalytic unit in the turbine exhaust flow stream. However, the location in the HRSG must be coordinated with the combined combustion turbine/duct burner exhaust temperature and flow. The design basis for catalyst volume for a given conversion efficiency would be a design optimization of catalyst cost versus gas flow pressure drop and ductwork cost.

Gas flow composition will affect conversion efficiency. Composition effects are minimized at elevated temperatures but should be taken into account during initial reactor design. Water vapor and low CO concentrations will result in lower catalyst activity. Degradation of catalyst activity over time due to poisoning, thermal shock, fouling, sintering, or vibration must be considered in the reactor design. Activity loss may or may not be reversible, depending on the nature of degradation. Washing/cleaning can sometimes regenerate activity; however, extensive catalytic ingredient and/or support damage will require catalyst replacement.

The presence of SO_2 in the gas stream (oil firing) can significantly reduce CO conversion rates and temporarily degrade conversion after the SO_2 constituent has been eliminated. This is an important consideration for fuel switching applications such as expected for two of these G machines. When firing fuel oil containing sulfur, the SO_2 combustion product can have a detrimental impact on catalyst performance. The durability of catalyst in the presence of SO_2 is significant for achieving long term, reliable catalytic conversion efficiency. SO_2 related degradation can be characterized by both a short term inhibition effect and a long term activity loss of the catalyst.

The short term inhibition effect is due to adsorption of SO_2 on the catalyst and carrier which may limit contact area between CO and catalyst. This loss of catalyst activity can be partially or totally recovered by catalyst operation without SO_2 at elevated temperatures (gas firing). Studies have shown that extended operation in a sulfur free environment at temperatures up to 1100°F is required to desorb strongly adsorbed SO_2 species. Long term catalyst activity loss can occur from extended operation in SO_2 environments when SO_2 reacts with the catalyst carrier to form sulfates. Activity loss due to sulfation cannot be effectively regenerated by gas firing washing or cleaning of the catalyst. Given that only ultra low-sulfur fuel oil (0.0015% S) will be fired and annual operation on oil will be limited, it is expected that the effects described above will be negligible.

The operating temperature requirement of the catalyst may not be met during startup, thereby leading to variation in the system performance during these periods.

Efficient Combustion

Because CO and VOC emissions are a function of combustor operating conditions, the formation of CO and VOC can be minimized by ensuring that the temperature in the combustion chamber and oxygen availability are adequate for complete combustion of the fuel. Usually, incomplete combustion results in formation of CO and VOC. As explained in Section 5.0 of Georgia Power's permit application, excess air can reduce CO and VOC emissions but will potentially raise the peak flame temperature and thus increase NO_x emissions. So, the key to the best design lies in the ability to use all the oxygen available with input air for combustion, while controlling the temperature such that NO_x formation can be minimized.

According to Georgia Power, combustion turbines are designed to combust fuel as completely as possible by incorporating good combustion practices. The model "G" combustion turbine incorporates these features and has inherently low CO and VOC emissions. The Division concurs.

LAER Analysis for VOC

The applicant proposed catalytic oxidation as LAER for VOC emissions from the proposed combustion turbine combined-cycle project. Georgia Power proposes a LAER emissions limit when the turbine is firing natural gas of 1.0 ppm at 15% oxygen, with the duct burner not firing, and a limit of 1.8 ppm at 15% oxygen, with the duct burner firing, on a short term average basis. For the two turbines capable of firing fuel oil, Georgia Power proposes a LAER emissions limit, when the turbine is firing fuel oil, of 4.0 ppm at 15% oxygen. The Division reviewed the RBLC information submitted by as part of the permit application (sees Appendix of the permit application) and determined that there was insufficient information on "G" sized turbines, therefore Georgia Power conducted an additional search for emission limits from "G" sized turbines. The complete results are included with the permit application in Appendix A of this Preliminary Determination. The Division has summarized the results of this survey in Table 4-1. For comparison purposes, only emission limits with units of parts per million, corrected to 15% oxygen are included in Table 4-1.

The proposed limits are consistent with the limits for these similar turbines. The RBLC does include data from smaller "F" machines which have limits as low as 2.0 ppm at 15% oxygen when burning distillate oil. The Division believes that there is sufficient uncertainty in the emissions rate that can be achieved from the larger "G" machines using an oxidation catalyst, that the higher emission limit is necessary. Therefore, the Division has determined that the Applicant's proposal to use catalytic oxidation to minimize emissions of VOCs, with the emission limits described, constitutes LAER.

Table 4-1: Survey of "G" Turbine Emission Limits

Fuel and Operating Condition	VOC (ppm @ 15% O2)	CO limit (ppm @ 15% O2)
CT only - Gas	1.0 – 2.8	2.0 – 25.0
CT w/ DB - Gas	1.5 – 9.3	2.0 –30.3
CT only - Oil	6.0 – 7.0	8.0 –50.0
Fuel and DB not specified	1.0 – 5.1	2.0 – 22.3
Gas – DB not specified	2.0 – 4.0	2.0 – 25.0
Oil - DB not specified	4.0 – 13.0	7.0 – 90.0

BACT Analysis for CO

The potential control methods for CO are efficient combustion and catalytic oxidation. Since LAER for VOC is proposed to be achieved with catalytic oxidation, the Applicant proposes that BACT for CO will also be satisfied by this control option. A review of the RBLC confirms that catalytic oxidation is the most stringent control instituted on combustion turbines (Appendix A of the permit application). With catalytic oxidation, the Applicant proposed that the maximum CO emission rate be set at 1.8 ppm at 15% oxygen (13.9 lb/hr) over the normal operating range of each CT/HRSG when firing natural gas and 9.0 ppm at 15% oxygen (54.2 lb/hr) over the normal operating range of the two combustion turbines when firing oil as the backup fuel.

The applicant performed a full CO BACT analysis including energy, environmental, and economic impacts.

Energy Impacts:

The applicant indicated that there would be an increase in backpressure, due to the presence of the catalytic oxidation unit, which could reduce turbine output. This backpressure equates to a total capacity impact on the three combined-cycle blocks of about 1200 kW.

Environmental Impacts:

The applicant outlined the environmental issues that could be associated with the use of catalytic oxidation. These issues included disposal of spent catalyst, CO emissions during startup, and possible increased conversion of SO2 to SO3.

Economic Impacts:

The applicant performed a BACT economic analysis consistent with the EPA Air Pollution Control Cost Manual. One of the analyses was performed assuming that each CT/HRSG was operated 8760 hours per year on natural gas. Another analysis assumed operation of 7760 hours on natural gas and 1000 hours per year on the backup fuel oil (representative of a possible operating scenario for two of the proposed CTs). The results indicated a removal cost for CO in the range of about $1,600 to $1,750 per ton.

After considering all of the relevant BACT evaluation impacts, the Division has determined that catalytic oxidation constitutes BACT for CO.

Controls for Auxiliary Boilers

Georgia Power also plans to construct three auxiliary boilers, each nominally rated at 200 MMBtu/hr, one for each combined-cycle block, in order to heat critical components during startup. The emissions from these auxiliary boilers were included in the annual emissions calculations as described in the Introduction (Section 1.0) of this Preliminary Determination. Georgia Power proposes to limit operation of each of these boilers to an annual capacity factor of 10% so potential emissions from all of the auxiliary boilers will be relatively small. Even so, the applicant is proposing that these auxiliary boilers will incorporate low NO_x burners with flue gas recirculation to minimize NO_x emissions; they will only fire low ash gaseous fuels (primarily natural gas with some use of propane-air as a backup fuel); and they will be designed for efficient combustion to minimize CO and VOC emissions. For these boilers, Georgia Power proposed a CO limit of 50 ppm, corrected to 15% oxygen, and a VOC limit of 12 ppm, corrected to 15% oxygen, as methane. The Division has converted these limits to their equivalent pounds per million Btu limits of 0.037 lb/MMBtu for CO and 0.0051 lb/MMBtu for VOC. A search of the RBLC found no similar boilers utilizing add-on control devices for CO or VOC. Table 4-2 contains the results of the RBLC search for these boilers. With the proposed controls, total annual emissions from Georgia Power’s auxiliary boilers will be under 5 tpy of NO_x, under 10 tpy of CO, and under 2 tpy of VOC. The Division agrees that the level of control represents BACT for CO and LAER for VOC.

Table 4-2: CO and VOC Limits – Auxiliary Boilers

Plant	Boiler Size	VOC / CO Control Device	Fuels	VOC limit (lb/MMBtu)	CO limit (lb/MMBtu)
FPL West County Energy Center (FL)	99.8 MMBtu/hr	None	Natural gas	N/A	0.08
Fore River Station (MA)	89.3 MMBtu/hr	None	Natural gas or Fuel oil	0.008	0.08
Sithe Edgar Development (MA)	89.3 MMBtu/hr	None	Natural gas or Fuel oil	0.008	0.08
Northern States Power Co. DBA Xcel Energy - Riverside Plant (MN)	160 MMBtu/hr	None	Natural gas	0.0050	0.0800
Calpine Turner Energy Center, LLC (OR)[1]	417,904 MMBtu/yr	None	Natural gas	0.0044	0.0380
Longview Power, LLC, Maidsville Plant (WV)	225 MMBtu/hr	None	Natural gas	0.0054	0.0400
Rocky Mountain Energy Center, LLC (CO)	129 MMBtu/hr	None	Natural gas	N/A	0.0390
Wisconsin Public Service (WI)	129 MMBtu/hr	None	Natural gas	0.0054	0.0800

[1]The RBLC includes a note on Calpine Turner Energy Center stating, "Facility will never be built. Did not receive a site certificate from the Oregon Energy Facility Siting Council."

Controls for Cooling Towers

A new cooling tower will be constructed to support operation of the first combined-cycle block (Unit 4). Two cooling towers are currently under construction and expected to go into service no later than June 2008 to support the existing coal-fired units. After retirement of the first coal-fired unit (McDonough Unit 2), one of the existing cooling towers will be reconfigured to support operation of the second combined-cycle block (Unit 5). After retirement of the second coal-fired unit (McDonough Unit 1), the second existing cooling tower will be reconfigured to support operation of the third combined-cycle block (Unit 6). All of these cooling towers will include high efficiency drift eliminators and plume abatement systems to control water carryover into the atmosphere and therefore reduce particulate matter emissions, which is the only known particulate control method. This type of design should keep drift to 0.005% of flow. This is in contrast to a default drift value of 0.02% used in the EPA AP-42 document, a factor of 4 lower. The Division agrees with the applicant that the drift eliminators and plume abatement systems will minimize particulate matter emissions from the cooling towers. The Division agrees that the permit need not include PM/PM_{10} emission limits for cooling towers, due to negligible PM/PM_{10} emissions expected, and because of technical limitations associated with measuring these emissions.

Controls for Emergency Fire Water Pump

The proposed McDonough combined-cycle project may include a diesel-fueled emergency firewater pump. The exact size has not been finalized, but is expected to be rated approximately 208 hp. Operation of the firewater pump will be limited to weekly testing and emergency use. The firewater pump will be limited to operation no more than 500 hours per year and burn ultra low sulfur distillate fuel oil.

Statewide Compliance Demonstration

Georgia Rule 391-3-1-.03(8)(c)3. requires that the owner or operator of the proposed new or modified source has demonstrated that all major stationary sources owned or operated by it (or by an entity controlling, controlled by, or under common control with such person) in the State, are subject to emission limitations and are in compliance, or on a schedule for compliance, with all applicable emission limitations and standards under the Clean Air Act.

Georgia Power is the owner or operator, or is under common control with the owner or operator, of the following major sources in Georgia:

- Boulevard Combustion Turbine-Electric Generating Plant; Savannah, GA
- Bowen Steam-Electric Generating Plant; Cartersville, GA
- Branch Steam-Electric Generating Plant; Milledgeville, GA
- Dahlberg Combustion Turbine-Electric Generating Plant; Nicholson, GA
- Hammond Steam-Electric Generating Plant; Coosa, GA
- Hatch-Electric Generating Plant; Waynesboro, GA
- Kraft Steam-Electric Generating Plant; Port Wentworth, GA
- McDonough Steam-Electric Generating Plant; Smyrna, GA
- McIntosh Combined Cycle Facility, Rincon, GA
- McIntosh Steam-Electric Generating Plant; Rincon, GA
- McManus Steam-Electric Generating Plant; Brunswick, GA
- Mitchell Steam-Electric Generating Plant; Albany, GA
- Robins Combustion Turbine-Electric Generating Plant; Warner Robins, GA
- Scherer Steam-Electric Generating Plant; Juliette, GA
- Vogtle-Electric Generating Plant; Waynesboro, GA
- Wansley Steam-Electric Generating Plant; Roopville, GA
- Wilson Combustion Turbine-Electric Generating Plant; Waynesboro, GA
- Yates Steam-Electric Generating Plant; Newnan, GA

All of these sources are currently in compliance with all applicable Clean Air Act requirements. Three of these plants; Bowen, Kraft, and Scherer; were issued Notices of Violation (NOV) issued by U.S. EPA in November 1999. Georgia Power disputes the alleged violations at these three plants. This case has not yet reached a final resolution. The Division has not alleged any violations in this matter. Therefore, Georgia considers that all of the major stationary sources owned and operated by Georgia Power in this State are in compliance with all applicable air quality requirements.

5.0 TESTING AND MONITORING REQUIREMENTS

Each Combined-Cycle System (Combustion Turbine and Its Paired Duct Burner)

Requirements for NO_x

NSPS Subpart KKKK requires an initial NO_x performance test using Method 7E. Subpart KKKK requires one of two methods of determining continuous compliance. The first method involves either (a) annual performance tests in accordance with 40 CFR 60.4400, if not using water or steam injection to control NO_x emissions, or (b) the installation of a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine, if burning a fuel that requires water or steam injection for compliance. The second method of determining continuous compliance under Subpart KKKK involves the use of one of the several listed continuous monitoring systems, including a continuous emission monitoring system as described in 40 CFR 60.4335(b) and 60.4345.

Continuous compliance with the NO_x emission limitations of Subpart KKKK will be demonstrated with a NO_x CEMS in keeping with 40 CFR 60.4335(b)(1), 60.4340(b)(1), and 60.4345. Each NO_x CEMS must be installed and certified according to Performance Specification 2 of 40 CFR Part 60, Appendix B, except that the 7-day calibration drift is to be based on unit operating days, not calendar days.

Three-hour rolling NO_x emission measurements by the NO_x CEMS satisfy the periodic monitoring requirement for the non-NSPS NO_x emission limits. The three-hour rolling NO_x emission measurements will also satisfy the Subpart KKKK NO_x emission limits, even though those limits are based on a four-hour rolling average because, for the same numerical value, an emission limit based on a three-hour average is more stringent than one based on a four-hour average. Therefore, so long as the three-hour NO_x CEMS average concentrations are less than either 15 ppm or 42 ppm, as applicable, the Division concludes that the NO_x CEMS can be used to demonstrate continuous compliance with the Subpart KKKK NO_x emission limits. An excess emissions for NSPS purposes, therefore, will consist of any unit operating period in which the 3-hour rolling average NO_x emission rate exceeds either 15 ppm or 42 ppm, as applicable.

The Acid Rain regulations require that the NO_x mass emission rate from each combustion turbine and its paired duct burner be 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.

To reasonably assure compliance with the non-NSPS NO_x emission limitations imposed in keeping with the State's ozone nonattainment planning, the Permittee must install, calibrate, operate, and maintain a NO_x CEMS for periodic monitoring of NO_x emissions from each combustion turbine and its paired duct burner. Satisfaction of the above 40 CFR Part 75 and 40 CFR Part 60 NO_x CEMS requirements will meet these ozone-related NO_x monitoring requirements.

Requirements for CO

Compliance with the BACT CO emission limitations for each combustion turbine and its paired duct burner must be demonstrated by an initial performance test using Method 10, the method for compliance determination. For each of the combined-cycle systems, which include combustion turbines with emission unit ID Nos. CT4A and CT5A, separate tests must be conducted while burning natural gas and ultra low sulfur diesel fuel. Because the Division is requiring the use of CO CEMS (discussed below), annual performance testing is not required.

To reasonably assure compliance with the BACT CO emissions limitations, the proposed permit requires a CO CEMS for the periodic monitoring of the discharge from each combustion turbine and its paired duct burner. Each CO CEMS is also used to determine the CO mass emissions on an annual basis from each such combined-cycle system to verify compliance with the PSD annual CO limits. Each CO CEMS must be installed and certified according to Performance Specification 4A of 40 CFR Part 60, Appendix B, except that the 7-day calibration drift is to be based on unit operating days, not calendar days.

Requirements for SO_2

NSPS Subpart KKKK requires the total sulfur content of the fuel to be monitored. However, if a fuel is demonstrated not to exceed potential sulfur emissions of 0.060 lb SO_2/MMBtu heat input, then the Permittee may elect not to monitor the sulfur content of that fuel. In keeping with the provisions of 40 CFR 60.4365, the Permittee will therefore demonstrate that neither the pipeline quality natural gas nor the ultra low sulfur diesel fuel contains potential sulfur emissions in excess of 0.060 lb SO_2/MMBtu.

The Acid Rain regulations require that SO_2 mass emissions from each combustion turbine and its paired duct burner 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 firing pipeline quality natural gas will be estimated using the regulatory default SO_2 emission rate of 0.0006 lb SO_2/MMBtu and the applicable quantity of natural gas burned in the combustion turbine and its paired duct burner. The heat content for the natural gas is 1020 Btu/scf. SO_2 mass emissions from combustion turbines with emission unit ID Nos. CT4A and CT5A 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 (15 ppm).

Requirements for VOC

The permit includes an initial performance test for VOC emissions from each combustion turbine and its paired duct burner to verify compliance with the VOC LAER emission standards. Method 25A performance testing will be the compliance determination method for VOC. There is no reliable and readily available method for long-term, continuous monitoring of VOC emissions from the type of fuel-burning equipment proposed by the Permittee. Each combined-cycle system will be equipped with catalytic oxidation systems to control emissions of both VOC and CO. The Division believes that VOC emissions from each combined-cycle system will be in compliance with the VOC LAER emission standards as long as the CO emissions from those systems are in compliance with the corresponding CO BACT emission limits. The CO CEMS therefore will also constitute periodic monitoring for VOC.

Requirements for Particulate Matter and Opacity

The combustion turbine component of each combined-cycle system will be able to fire natural gas. However, only combustion turbines with emission units ID Nos. CT4A and CT5A will also be able to burn ultra low sulfur diesel fuel. Natural gas and ultra low sulfur diesel are both low-ash fuels. Each combustion turbine and each duct burner are designed to achieve highly efficient (complete) combustion. Consequently, the Division believes each combined-cycle system will emit negligible amounts of particulate matter and visible emissions. Because the magnitude of those emissions are expected to be comfortably below their allowable levels, performance testing for particulate matter and visible emissions will be conducted only on the two combined-cycle systems which include CT4A and CT5A. Each system will be tested while its combustion turbine fires natural gas and also while it fires ultra low sulfur diesel. Compliance with the particulate matter and visible emissions limits will be determined using Method 5T and Method 9, respectively. Method 9 also will be the basis for periodic monitoring of visible emissions, when the Department deems necessary. So long as the combined-cycle systems, including their air pollution control devices, are properly operated and maintained, the Division is reasonably assured of continuous compliance with the PM emission limit without the need for any other periodic monitoring.

Requirements for Formaldehyde

The permit includes an initial performance test for formaldehyde emissions from the two combined-cycle systems whose combustion turbines (emission unit ID Nos. CT4A and CT5A) will burn ultra low sulfur diesel fuel. The Part 63, Subpart YYYY formaldehyde emission limit is not applicable whenever those combustion turbines are firing natural gas. Method 320 of Appendix A to 40 CFR Part 63 constitutes the compliance determination method for formaldehyde emission. In addition, periodic monitoring for compliance with the formaldehyde emissions limit is provided by continuous measurement of the inlet temperature to the oxidation catalyst on each unit. Subpart YYYY prescribes an operating limitation whereby the 4-hour rolling average of the inlet temperature to the catalyst must remain within the temperature range suggested by the catalyst manufacturer.

The combustion turbines with emission unit ID Nos. CT4A or CT5A are subject to the formaldehyde emission limitation when it is classified under Part 63 as a “lean premix oil-fired stationary combustion turbine.” That classification applies in any calendar year in which (1) that combustion turbine burns ultra low sulfur diesel fuel, and (2) all new and existing combustion turbines at the site burn distillate oil, in the aggregate, for more than 1000 hours. Thus, after any given year it is possible for combustion turbines CT4A and/or CT5A to change from an “oil-fired” unit, to which the Part 63 formaldehyde emission limit and related testing and monitoring apply, to a “gas-fired” unit which is not subject to Part 63, or vice versa.

Each Auxiliary Boiler

Emission limitations have been proposed for CO, VOC, NO_x, particulate matter, and visible emissions from each auxiliary boiler. Because these boilers will fire only natural gas and propane-air, and because the operation of each boiler is limited to the equivalent of less than a 10% annual capacity factor, and there are no add-on control devices, the Division is requiring compliance with the boilers’ emission limits for CO and VOC to be determined by an initial performance test only on the first of the three auxiliary boilers, i.e., emission unit ID No. AB04, while firing natural gas. For the same reasons, compliance with the boilers’ emission limit for particulate matter can be demonstrated using the applicable AP-42 emission factor. So long as the auxiliary boilers burn only natural gas and propane-air and are properly operated and maintained, the Division believes that no additional periodic monitoring is necessary for CO, VOC, particulate matter, and visible emissions.

The auxiliary boilers are subject to Georgia Rule 391-3-1-.02(2)(lll), which limits NOx emissions during the period May 1 through September 30 of each year. Section 2.119 of the Division’s Procedures for Testing and Monitoring Sources of Air Pollutants contains the testing and monitoring requirements for Rule (lll). Section 2.119 requires that each boiler be equipped with a CEMS to measure NOx and oxygen concentration. A predictive system is allowed in lieu of the CEMS. Section 2.119 further requires that the initial performance test be conducted using this monitoring system.

<u>CAM Applicability:</u>

The combustion turbines are 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, are 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 combustion turbines use a catalytic oxidizer to control carbon monoxide and volatile organic compounds and a selective catalytic reduction unit to control nitrogen oxides. CAM is applicable for these pollutants because (1) the permit contains emission limitations for each pollutant, (2) a control device will be utilized to meet the emission limitation, and (3) without the control device, the emissions from each unit would exceed the major source thresholds (100 tons per year for CO and 25 tons per year for VOC and NOx). Furthermore, because the post control emissions of each of these pollutants exceed the major source thresholds, these units are considered large pollutant specific emission units (PSEUs).

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 Georgia Power triggers PSD review for CO. An air quality analysis was conducted to demonstrate the facility's compliance with the NAAQS for CO. PSD Increment analysis was not required since there is not an increment for CO. 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. An additional analysis was conducted to demonstrate compliance with the Georgia air toxics program (see Section 7.0 of this Preliminary Determination).

Modeling Requirements

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

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

Significance Analysis: Ambient Monitoring Requirements and Source Inventories

Initially, a Significance Analysis is conducted to determine if the CO emissions increases at Plant McDonough would significantly impact the area surrounding the facility. Maximum ground-level concentrations are compared to the pollutant-specific U.S. EPA-established modeling significant level (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 MSL) does not result, no further modeling analyses would be conducted for that pollutant for NAAQS. 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.

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 assessment is required for CO.

If any off-site pollutant impacts calculated in the Significance Analysis exceed the MSL, a Significant Impact Area (SIA) would be determined. The SIA encompasses a circle centered on the plant 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.

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)
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." As noted in Table 6-2 below, no secondary NAAQS have been developed for CO.

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

Pollutant	Averaging Period	NAAQS	
		Primary / Secondary (ug/m^3)	Primary / Secondary (ppm)
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 the Georgia Power, 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.

Modeling Methodology

AERMOD (version 07026) was used for this modeling analysis. 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 in Appendix C of this Preliminary Determination and in Section 8.0 of the permit application.

Modeling Results

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

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

Pollutant	Averaging Period	Year	UTM East (km)	UTM North (km)	Maximum Impact (ug/m^3)	MSL (ug/m^3)	Significant?
CO	1-hour	2004	734.745	3,746.066	1784.3	2000	No
	8-hour	2006	734.759	3,745.724	206.04	500	No

Data for worst year provided only.

As indicated in the tables above, maximum modeled impacts were below the corresponding MSLs for CO.

Ambient Monitoring Requirements

Table 6-5: 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?
CO	8-hour	2006	734.759	3,745.724	575	206.04	No

Data for worst year provided only

The impact for CO 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. Because the maximum modeled impact is below the corresponding de minimis concentrations, no pre-construction monitoring is required for CO.

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. For this facility, a distance of 200 kilometers is being used to define "near".

The one Class I area within 200 kilometers of Plant McDonough is the Cohutta Wilderness Area, located approximately 125 kilometers north of the facility. The U.S. Fish and Wildlife Service (FWS) is the designated Federal Land Manager (FLM) responsible for oversight of the Cohutta Wilderness Area. Since CO does not cause an impairment of visibility, a Class I area analysis was not required as part of this application.

7.0 ADDITIONAL IMPACT ANALYSES

PSD review requires an analysis of impairment to visibility, soils, and vegetation that will occur as a result of the proposed project for those pollutants for which the project is subject to review. In addition, PSD review also requires the applicant to provide an analysis of the air quality impact projected for the area as a result of the general commercial, residential, industrial, and other growth associated with the facility. Other impact analysis requirements may also be imposed on a permit applicant under local, State or Federal laws outside the PSD review process.

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 dioxides – absorb or scatter light. The absorption of light reduces the amount of light received from viewed objects and the scattering of light scatters ambient light into the line of sight, appearing as haze.

Carbon Monoxide emissions do not impact visibility. Therefore, the project will not impact Class I and Class II visibility for purposes of PSD review of the project. Since acquiring VOC emission reduction credits is required to ensure an improvement in air quality by reducing emissions in non-attainment pollutants, VOCs emissions from the project will not adversely impact visibility.

Soils and Vegetation
The EPA has developed a set of screening concentrations for evaluation of project impacts on soils and vegetation. These screening concentrations are contained in the EPA document entitled “A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals” (EPA-450/2-81-078). The CO screening concentration is 1,800,000 µg/m3 based on a one-week exposure period. According to the analysis provided by the Applicant, the maximum predicted 8-hour CO concentrations during steady-state and start-up operating conditions are 19.9 µg/m3 and 206.0 µg/m3, respectively. Based on a comparison of these maximum predicted concentrations to the screening concentration, EPD concludes that the projected CO emissions will not adversely affect soils or vegetation

Growth
The analysis provided by the Applicant in Chapter 9 of the air quality permit application demonstrates that there will be no significant growth-related air pollution impacts associated with construction of the combined-cycle electric generating units at Plant McDonough.

Alternatives Analysis
Pursuant to the provisions of the Georgia Rules for Air Quality Control at 391-3-1-.03(8)(c)4., the applicant for a project that undergoes non-attainment New Source Review must include with the application an analysis of alternative sites, sizes, production processes, and environmental control techniques that demonstrates that the benefits of the proposed modification significantly outweigh the environmental and social costs. This analysis was submitted as part of the Applicant’s air quality permit application on March 8, 2007.

<u>Alternate Sites:</u>
Georgia Power has considered alternative sites. Plant McDonough was selected as the preferred location primarily due to continuing electric load growth that has outpaced local generation additions in northeast Georgia and the Atlanta metro area. In 2004, Georgia Power Company projected long term reliability issues due to a lack of generation relative to continuing load growth on the transmission system in Atlanta and portions of northeast Georgia (collectively the Northeast Georgia Area). These area-specific reliability issues were projected to become critical beginning in 2011 and increase in magnitude through time. The ability to add new generation in this region is limited by location of suitable sites with transmission access, adequate water supply, adequate fuel delivery options, and environmental considerations. In addition, generation solutions must support reliability of the electric system. In light

of these limitations, the ability to utilize the existing McDonough site and infrastructure to add new capacity and replace retiring capacity is paramount to maintaining reliability and the cost effectiveness of the integrated generation and transmission system. Additionally, the proposed construction of Plant McDonough Units 4, 5, and 6, coupled with the proposed retirement of Plant McDonough Units 1 and 2, provides a unique opportunity to utilize existing resources, capitalize on economies of scale, and reduce overall emissions in the Atlanta metro area.

According to the Applicant, seven potential sites were identified for an initial review. Total costs, risks and benefits associated with each site were considered in this preliminary review which included engineering and construction estimates. The two most promising sites were subjected to a more detailed review. The result of this analysis clearly shows the McDonough site as the most efficient site for placement of generation resources that best meet essential transmission system reliability needs for Atlanta and northeast Georgia in the most economic and environmentally responsible manner as outlined below.

In addition to transmission reliability and environmental factors previously discussed, selection of McDonough is also based on site specific life-cycle economics and issues. Factors evaluated relate to engineering and construction, land and land availability, fuel supply, and life-cycle operation and maintenance.

The planned combined cycle units at McDonough will require construction of a gas lateral pipeline approximately 20 miles in length. While the pipeline is outside the scope of this air permit, the impacts from the pipeline are expected to be minimized through the use of existing utility corridors. Alternate generation sites considered also would require construction of similar pipelines. With respect to project right-of-way requirements, locating generation at McDonough best avoids major transmission projects and associated right-of-way difficulties.

Alternative Sizes and Production Processes:

Georgia Power evaluated alternative sizes and production processes as well. Georgia Power projects future generation needs as a part of its Integrated Resource Plan (IRP). Both the approved 2004 IRP and the filed 2007 IRP shows the continued selection of combustion turbine and combined cycle technology as the most viable and economical generation supply from now through 2014. In selecting these technologies, a comparison of historical data to equipment performance expectations was performed. Georgia Power submitted both the F and G technology combined-cycle proposals for evaluation. The evaluation consisted of a detailed compilation and review of efficiency, reliability and environmental performance data. The evaluation resulted in the net present value of each the F and the G technologies in $ per kW. A further evaluation reviewed the economic benefits associated with including supplemental firing. The proposed McDonough Units 4, 5, and 6 combined cycle G technology was chosen by the applicant as the most economical technology to match capacity needs.

Alternative Environmental Control Techniques

The combined cycle units will have state-of-the-art emission controls. The turbines will have the manufacturer's latest dry low NO_x burner technology to minimize NO_x emissions and the combined cycle units will also have SCR technology to further reduce NO_x emissions. To ensure LAER for VOCs, all of the combined-cycles will have catalytic oxidation systems. The catalytic oxidation system will also control and reduce CO emissions. As discussed in Section 5.0, the only post-combustion alternative to catalytic oxidation is thermal oxidation, which would increase fuel usage and NO_x emissions, which is undesirable in an ozone non-attainment area. The new forced draft cooling towers at the site will be equipped with both drift eliminators and plume abatement technology which will minimize PM emissions. There are no other controls that would be more effective than the proposed technologies.

Cost / Benefit Analysis and Conclusion

By selecting the McDonough site, Georgia Power achieves the most economical and environmentally beneficial generation that meets long term transmission reliability requirements and makes the best and most efficient use of Georgia's natural resources. Location of generation resources near load centers is more cost effective and efficient in reducing transmission system losses and thereby reduces the amount of generation necessary to meet demand. Location at McDonough is not only the most cost effective but will also greatly improve the reliability of the transmission system and Georgia Power's ability to assure adequate power for the Atlanta area and North Georgia.

The McDonough site will result in a net air quality benefit for Georgia and the Atlanta metro area because it will enable Georgia Power to retire the two coal-fired units at Plant McDonough. This will result in a large reduction in NO_x, SO_2 and particulate emissions, and the projected increase in VOC emissions from the project will be offset at a 1.3 to 1 ratio. The reduction in NO_x, SO_2 and PM emissions will help the State make progress toward attainment of the ozone and $PM_{2.5}$ standards in the Atlanta area. It is clear that the proposed project will result in significant environmental benefits over the status quo.

In addition, given the proximity of the site to a municipal landfill, the new units are being designed to burn landfill gas as a supplemental fuel. By accepting landfill gas, the project will eliminate the need to flare those gases into the atmosphere at the landfill.

Furthermore, with this project, Georgia Power is redeveloping an existing site located on industrial developed land as opposed to developing a green field site. The McDonough site has adequate water withdrawal permits and will not need additional intake or discharge structures to be built. The ability to interconnect to an existing transmission infrastructure will also provide an environmental benefit because new 500 kV transmission lines will not be needed.

It is the Preliminary Determination of EPD that, based on an analysis of alternative sites, sizes, production processes, and environmental control techniques, the Applicant has adequately demonstrated that the benefits of the proposed modification outweigh the environmental and social costs.

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 Rule 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)* (Georgia Air Toxics Guideline).

Selection of Toxic Air Pollutants for Modeling

Georgia Power conducted modeling for the TAPs that have emission factors in Section 3.1 (Stationary Gas Turbines) of EPA's Compilation of Air Pollutant Emission Factors (AP-42). Georgia Power did excluded 1, 3-butadiene and propylene oxide, which are noted in AP-42 as not being detected. In addition, Georgia Power modeled for ammonia, which can reasonably be expected from the SCR control device, and for sulfuric acid mist, which may be generated from combustion of fuels with sulfur.

Toxic Air Pollutant Modeling Results

Georgia EPD used the ISCST3 dispersion model to re-evaluated the modeling submitted by Georgia Power. Details of the modeling can be found in EPD'S PSD Dispersion Modeling and Air Toxics Assessment Review in Appendix C of this Preliminary Determination and in Section 8.0 of the permit application. All modeled TAP concentrations were found to be less than the established Acceptable Ambient Concentration (AAC) values.

8.0 EXPLANATION OF DRAFT PERMIT CONDITIONS

The permit requirements for this proposed facility are included in draft Permit Amendment No. 4911-067-0003-V-02-2.

Section 1.0: Facility Description

The description section contains four paragraphs, describing their proposal to construct three combined-cycle generating blocks. Each power block will consist of two combustion turbines, two heat recovery steam generators (HRSG) with duct burners, one steam turbine, and associated support facilities. Contemporaneous with the startup of the new combustion turbines, Georgia Power will permanently shutdown the two existing coal-fired units at the site.

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

Six combustion turbines (emission unit ID Nos. CT4A, CT4B, CT5A, CT5B, CT6A, and CT6B), six HRSGs (emission unit ID Nos. DB4A, DB4B, DB5A, DB5B, DB6A, and DB6B), and three auxiliary boilers (emission unit ID Nos. AB04, AB05, and AB06) are being constructed and have been included in the Additional Emission Units Table 3.1.1.

Conditions 3.3.5 and 3.3.6 were added requiring the construction of the turbine blocks in a reasonable period of time, per PSD requirements.

Condition 3.3.7 was added to limit the fuels combusted in combustion turbines CT4A and CT5A to pipeline quality natural gas or ultra low sulfur diesel fuel. Only these turbines can fire fuel oil.

Condition 3.3.8 was added to limit the fuel combusted in combustion turbines CT4B, CT5B, CT6A, and CT6B to pipeline quality natural gas.

Condition 3.3.9 was added to limit the fuels combusted in duct burners DB4A, DB4B, DB5A, DB5B, DB6A, and DB6B to pipeline quality natural gas or landfill gas.

Condition 3.3.10 was added to limit the sulfur content of the fuel oil fired in combustion turbines CT4A and CT5A to 0.0015 percent sulfur by weight [equivalent to 15 ppm].

Condition 3.3.11 was added to require catalytic oxidation add-on control equipment to control all combustion turbines and duct burners as BACT for CO and as LAER for VOC.

Condition 3.3.12 was added to limit the CO and VOC emissions from each block on a twelve month basis. Blocks 4 and 5 are limited to 262 tons each of CO and 135 tons each of VOC. Block 6 is limited to 241 tons of CO and 132 tons of VOC.

Condition 3.3.13 was added to limit the time allowed for startup (based on the type of startup) and shutdown. The condition also defines three types of startup, based on the length of time the unit was shutdown.

Condition 3.3.14 was added to require the permanent shutdown of existing coal-fired unit SGM2 before CTs 4A, 4B, 5A, and 5B commence commercial operation.

Condition 3.3.15 was added to require the permanent shutdown of existing coal-fired unit SGM1 before CTs 6A and 6B commence commercial operation.

Condition 3.3.16 was added to require that each combustion turbine and its paired duct burner comply with 40 CFR 60 Subpart A – "General Provisions."

Condition 3.3.17 was added to limit pollutant emissions from each combustion turbine and its paired duct burner when the combustion turbine is fired with natural gas, during normal operations.

- 3.3.17a. limits NOx to 15 ppm, corrected to 15% oxygen, per 40 CFR 60 Subpart KKKK
- 3.3.17b limits NOx to 6.0 ppm, corrected to 15% oxygen, during the period May 1 through September 30 of each year, per Georgia Rule (nnn).
- 3.3.17c limits CO to 1.8 ppm, corrected to 15% oxygen, as BACT.
- 3.3.17d limits VOC to 1.8 ppm, corrected to 15% oxygen, as methane, while the duct burner is being fired, as LAER.
- 3.3.17e limits VOC to 1.0 ppm, correct to 15% oxygen, as methane, while the duct burner is not being fired, as LAER.
- 3.3.17f limits particulate matter to 0.10 pound per MMBtu, per Georgia Rule (d)
- 3.3.17g limits opacity to 20%, except for one 6-minute period in any hour of no more than 27%, per Georgia Rule (d).

Condition 3.3.18 was added to limit the annual operation of CT4A and CT5A while burning ultra low sulfur diesel fuel.

Condition 3.3.19 was added to limit the emissions from CT4A/DB4A and CT5A/DB5A when the combustion turbine is fired with ultra low sulfur diesel fuel.

- 3.3.19a limits NOx to 42 ppm, corrected to 15% oxygen, per 40 CFR 60 Subpart KKKK.
- 3.3.19b limits NOx to 6.0 ppm, corrected to 15% oxygen, during the period May 1 through September 30 of each year, per Georgia Rule (nnn)
- 3.3.19c limits CO to 9.0 ppm, corrected to 15% oxygen, as BACT.
- 3.3.19d limits VOC to 4.0 ppm, corrected to 15% oxygen, as methane, as LAER.
- 3.3.19e limits particulate matter to 0.10 pound per million Btu, per Georgia Rule (d).
- 3.3.19f limits opacity to 20%, except for one 6-minute period in any hour of no more than 27%, per Georgia Rule (d).

Condition 3.3.20 was added to require that CT4A/DB4A and CT5A/DB5A comply with 40 CFR 63 Subpart A – "General Provisions."

Condition 3.3.21 was added to limit the formaldehyde emissions from CT4A and CT5A to 91 ppb, corrected to 15% oxygen, when the combustion turbines burn ultra low sulfur diesel fuel, per 40 CFR 63, Subpart YYYY.

Condition 3.3.22 was added to require the operation of the oxidation catalyst on CT4A and CT5A at a temperature suggested by the catalyst manufacturer, per 40 CFR Part 63, Subpart YYYY and its requirement to control formaldehyde.

Condition 3.3.23 was added to require proper operation of CT4A or CT5A and their respective control devices, per 40 CFR 63, Subpart YYYY.

Condition 3.3.24 was added to limit the fuels burned in the auxiliary boilers to natural gas or propane-air, as specified in the application.

Condition 3.3.25 was added to limit each auxiliary boiler to 175,200 MMBtu per year (equivalent to an annual capacity factor of 10%), as specified in the application.

Condition 3.3.26 was added to limit the emissions from the auxiliary boilers.

- 3.3.26a limits CO to 0.037 lb/MMBtu, as BACT
- 3.3.26b limits VOC to 0.0051 lb/MMBtu, as LAER.
- 3.3.26c limits NOx to 30 ppm, corrected to 3% oxygen during the period May 1 through September 30 of each year, per Georgia Rule (lll).
- 3.3.26d limits particulate matter using an equation based on heat input rate, per Georgia Rule (d).
- 3.3.26e. limits opacity to 20%, except for one 6-minute period in any hour of no more than 27%, per Georgia rule (d).

Condition 3.3.27 was added requiring that Georgia Power obtain and retire 466 tons of VOC emission reduction credits prior to commencing operation of the new equipment.

Condition 3.3.28 was added to limit the NOx from each combustion turbine and its paired duct burner and the auxiliary boilers. With these limits, PSD-avoidance for NOx is assured and it is possible that Georgia Power may be able to take credit for some of the NOx reductions for banking purposes.

- 3.3.28a limits NOx from each combustion turbine to 2.0 ppm, corrected to 15% oxygen, when the combustion turbine is fired with pipeline quality natural gas.
- 3.3.28b limits NOx from each combustion turbine to 6.0 ppm, corrected to 15% oxygen, when the combustion turbine is fired with ultra low sulfur diesel fuel.
- 3.3.28c limits NOx from each auxiliary boiler to 15 ppm, corrected to 3% oxygen.

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

Condition 4.1.3 was modified to add the test methods required for the new emission units in this project.

Condition 4.2.2 was added to require performance testing on the combustion turbines while firing natural gas.

- 4.2.2a defines “affected facility” for purposes of this condition as the combination of each combustion turbine and its paired duct burner.
- 4.2.2b requires a test for NOx on each affected facility at 100% load, plus or minus 25%.
- 4.2.2c requires a test for CO on each affected facility at base load.
- 4.2.2d requires a test for VOC on each affected facility at base load with the duct burner firing.
- 4.2.2e requires tests for VOC on each affected facility at 60% load and base load with the duct burner not firing.

Condition 4.2.3 was added to require performance testing on CT4A and CT5A while firing ultra low sulfur diesel fuel.

- 4.2.3a defines “affected facility” for purposes of this condition as the combination of each combustion turbine and its paired duct burner.
- 4.2.3b requires a test for NOx on each affected facility at 100% load, plus or minus 25%.
- 4.2.3c requires a test for CO on each affected facility at base load.
- 4.2.3d requires a test for particulate matter on each affected facility at base load.
- 4.2.3e requires a test for visible emissions on each affected facility at base load.
- 4.2.3f requires tests for VOC on each affected facility at 60% load and base load.
- 4.2.3g requires a test for formaldehyde on each affected facility at 100% load, plus or minus 10%.

Condition 4.2.4 was added to require an annual test for formaldehyde from CT4A or CT5A if the aggregate total hours of operation on fuel oil for all turbines at the facility exceeds 1000 hours in a calendar year, per 40 CFR 63 Subpart YYYY.

Condition 4.2.5 was added to require the submission of a Notification of Compliance Status, in a timely fashion, following each formaldehyde test on CT4A or CT5A, per 40 CFR 63 Subpart YYYY.

Condition 4.2.6 was added to require performance testing on the auxiliary boilers.

- 4.2.6a requires a test for NOx on each auxiliary boiler.
- 4.2.6b requires a test for CO on AB04, which is to represent the other two auxiliary boilers.
- 4.2.6c requires a test for VOC on AB04, which is to represent the other two auxiliary boilers.

Condition 4.2.7 was added to require performance testing on the auxiliary boilers using the CEMS required by Condition 5.2.10c, per the requirements of the Division's Procedures for Testing and Monitoring Sources of Air Pollutants Section 2.119, which contains testing requirements for Georgia Rule (lll).

Section 5.0: Requirements for Monitoring

Condition 5.2.10 was added to require Continuous Emissions Monitoring Systems (CEMS) on each combustion turbine and its paired duct burner and on the auxiliary boilers.

- 5.2.10a requires a NOx CEMS on each combustion turbine and its paired duct burner, per monitoring requirements in 40 CFR 60 Subpart KKKK.
- 5.2.10b requires a CO CEMS on each combustion turbine and its paired duct burner, as monitoring to assure compliance with the CO BACT limits.
- 5.2.10c requires a NOx CEMS on each auxiliary boiler. Alternatively, a predictive system is allowed in lieu of the CEMS, per the requirements of the Division's Procedures for Testing and Monitoring Sources of Air Pollutants Section 2.119, which contains monitoring requirements for Georgia Rule (lll).

Condition 5.2.11 requires the installation of various monitoring devices on the combustion turbines, duct burners, and auxiliary boilers.

- 5.2.11a requires a monitor for the amount of natural gas burned in each combustion turbine.
- 5.2.11b requires a monitor for the amount of natural gas or landfill gas burned in each duct burner.
- 5.2.11c requires a monitor for the amount of ultra low sulfur diesel fuel burned in CT4A and CT5A.
- 5.2.11d requires a monitor for the amount of natural gas and propane-air burned in each auxiliary boiler.
- 5.2.11e requires a monitor for the time that oil is fired in CT4A and CT5A.
- 5.2.11f requires a monitor for the time that oil is fired in each existing combustion turbine at the site.
- 5.2.11g requires a monitor for the temperature at the inlet of the catalyst on CT4A and CT5A, per 40 CFR 63 Subpart YYYY and its requirement to monitor for formaldehyde when firing oil.

Condition 5.2.12 was added to require the submittal of the sulfur content of the pipeline quality natural gas burned in the combustion turbines and duct burners, per 40 CFR 60 Subpart KKKK.

Condition 5.2.13 was added to require that the ultra low sulfur diesel comply with the sulfur content for Grade No. 1-D S15 or No. 2-D S15 as defined ASTM D975-06, per 40 CFR 60 Subpart KKKK.

Condition 5.2.14 was added to require monitoring of the sulfur content of the landfill gas burned in the duct burners, per 40 CFR 60 Subpart KKKK.

Condition 5.2.15 was added to require application of Appendix F, Procedure 1 (40 CFR Part 60, Appendix F) to the CO CEMS installed on the combustion turbines.

Condition 5.2.16 was added to set minimum data availability requirement for the CO CEMS installed on the combustion turbines, as part of the monitoring to assure compliance with BACT limits.

Conditions 5.2.17 through 5.2.19 were added to include the CAM plans for the combustion turbines.

Section 6.0: Other Record Keeping and Reporting Requirements

Condition 6.1.7 was modified to define the appropriate excess emissions, exceedances, and excursions for the monitoring required on the new emission units.

Condition 6.1.8 was added to require the submittal of deviation information required by 40 CFR 63 Subpart YYYY.

Condition 6.2.15 was added to require the retention of monthly natural gas usage records for the combustion turbines and the duct burners, per 40 CFR 60 Subpart KKKK.

Condition 6.2.16 was added to require the retention of ultra low sulfur diesel fuel usage records for CT4A and CT5A, per 40 CFR 60 Subpart KKKK.

Condition 6.2.17 was added to require records of the duration and type of startup on each turbine.

Condition 6.2.18 was added to require the calculation of three-hour rolling average NOx emission rates for each combustion turbine and its paired duct burner, to verify compliance with the NOx emission limits in Conditions 3.3.26a and 3.3.26b.

Condition 6.2.19 was added to require the calculation of 30-day rolling average NOx emission rates for each combustion turbine and its paired duct burner, to verify compliance with the NOx emission limits in Conditions 3.3.17a and 3.3.19a.

Condition 6.2.20 was added to require the calculation of hourly NOx mass emission rate from each combustion turbine and its paired duct burner, which is required by Condition 6.2.21.

Condition 6.2.21 was added to require the calculation of monthly NOx mass emission rates from each combustion turbine and its paired duct burner, which is required by Condition 6.2.22.

Condition 6.2.22 was added to require the calculation of a twelve-month total NOx emission rate from each combustion turbine and its paired duct burner, at the end of each month, to verify compliance with the NOx emission limits in Condition 3.3.12c.

Condition 6.2.23 was added to require the calculation of three-hour rolling average CO emission rates for each combustion turbine and its paired duct burner, to verify compliance with the CO emission limits in Conditions 3.3.17c and 3.3.19c.

Condition 6.2.24 was added to require the calculation of hourly CO mass emission rate from each combustion turbine and its paired duct burner, which is required by Condition 6.2.25.

Condition 6.2.25 was added to require the calculation of monthly CO mass emission rates from each combustion turbine and its paired duct burner, which is required by Condition 6.2.26.

Condition 6.2.26 was added to require the calculation of a twelve-month total CO emission rate from each combustion turbine and its paired duct burner, at the end of each month, to verify compliance with the CO emission limits in Condition 3.3.12a.

Condition 6.2.27 was added to require the calculation of monthly and twelve-month total heat input for each auxiliary boiler each month, to verify compliance with the heat input limit in Condition 3.3.25.

Condition 6.2.28 was added to require the calculation of the twelve-month oil-fired operating time for CT4A and CT5A at the end of each month, to verify compliance with the oil-fired operating time limit in Condition 3.3.18.

Condition 6.2.29 was added to require the calculation of the calendar year oil-fired operating time for all combustion turbines at the site, to determine whether the requirement in Condition 4.2.4, to conduct a formaldehyde emission test on CT4A and/or CT5A within 90 days of the end of the calendar year, is triggered.

Condition 6.2.30 was added to require the notification of key dates and events to the Division, mainly for NSR purposes.

- 6.2.30a requires the notification of actual date of commencement of construction of each combustion turbine and its paired duct burner and of each auxiliary boiler.
- 6.2.30b requires the notification of the actual date of initial startup of each combustion turbine and its paired duct burner and of each auxiliary boiler.
- 6.2.30c requires the notification of the actual date that the McDonough steam generating units are permanently shutdown.
- 6.2.30d requires the certification that the construction of each combustion turbine and its paired duct burner and of each auxiliary boiler has been completed in accordance with the application, plans, specifications and supporting documents submitted in support of this permit.
- 6.2.30e requires certification that the McDonough steam generating units have been permanently shut down before the commercial operation startup of the applicable combined-cycle systems.

Condition 6.2.31 was added to require the quarterly submittal of various required monitoring activities, including: (a) the heat input to each auxiliary boiler, (b) the twelve-month total heat input to each auxiliary boiler, (c) the monthly oil-fired operating time for CT4A and CT5A, (d) the twelve-month oil-fired operating time for CT4A and CT5A, (e) the twelve-month CO mass emissions from each combustion turbine and its paired duct burner, (f) identification of each month that the minimum data availability of CO was not met, (g) identification of the Out-of-Control Periods for the CO CEMS, (h) the results of daily CO CEMS drift tests and quarterly accuracy assessments, and (i) the results of quarterly CO CGAs

Condition 6.2.32 was added to require timely submittal of the RATA conducted on the CO CEMS.

Condition 6.2.33 was added to require the submittal of certain information required by 40 CFR 63 Subpart YYYY.

Condition 6.2.34 was added to require the submittal of a Notification of Compliance Status following each formaldehyde test on CT4A and CT5A, per 40 CFR 63 Subpart YYYY.

Condition 6.2.35 was added to require retention of the following records: (a) a copy of each notification and report that was submitted to comply with 40 CFR 63 Subpart YYYY, (b) records of performance tests and performance evaluations, (c) records of the occurrence and duration of each startup, shutdown or malfunction, (d) records of the occurrence and duration of each malfunction of the catalytic oxidation control equipment, if any, and (e) records of all maintenance on the catalytic oxidation control equipment.

Condition 6.2.36 was added to require the retention of records for 5 years, per 40 CFR 63 Subpart YYYY and 40 CFR Part 70.

Condition 6.2.37 was added to require the submittal of the inlet temperature range suggested by the catalyst manufacturer for CT4A and CT5A, per 40 CFR 63 Subpart YYYY.

<u>Section 7.0: Other Specific Requirements</u>

No conditions in Section 7.0 are being added, deleted or modified as part of this permit action

APPENDIX A

Draft Revised Title V Operating Permit Amendment
Georgia Power Company – Plant McDonough
Smyrna (Cobb County), Georgia

APPENDIX B

Georgia Power Company – Plant McDonough Permit Application and Supporting Data

Contents Include:

1. PSD Permit Application No. 17297, dated March 5, 2007
2. Additional Information Package, dated July 25, 2007
3. CAM Plans, dated August 15, 2007

APPENDIX C

EPD'S PSD Dispersion Modeling and Air Toxics Assessment Review