Prevention of Significant Air Quality Deterioration Review
Of the Savannah Electric and Power Company
McIntosh Combined-Cycle Facility
located in Rincon, Effingham County, Georgia

PRELIMINARY DETERMINATION
SIP Permit Application No. 13404
Phase II Acid Rain Permit Application No. AR-13746
Title V Permit Application No. 13404
February 2003

<u>Reviewing Authority</u>

Georgia Department of Natural Resources
Environmental Protection Division
Air Protection Branch

Ron Methier – Chief, Air Protection Branch

Stationary Source Permitting Program	Planning & Support Program
James Johnston, P.E.	Dale Kemmerick
James Capp	James Stogner
Susan Jenkins	

SUMMARY

The Environmental Protection Division (the Division or EPD) has reviewed the Savannah Electric and Power Company – McIntosh Combined-Cycle Facility application to construct and operate four combined-cycle combustion trains (i.e., two combined-cycle power blocks) at the existing McIntosh Steam-Electric Generating Plant (a.k.a. Plant McIntosh) site in Rincon, Effingham County, Georgia. The Plant McIntosh facility consists of one nominal 177-megawatt coal-fired unit, eight nominal 80-MW simple cycle combustion turbines, and ancillary equipment. Plant McIntosh and the McIntosh Combined-Cycle Facility constitute one site for Title I and Title V purposes.

The Plant McIntosh expansion, referred to as the McIntosh Combined-Cycle Facility, consists of two combined-cycle power blocks. Each combined-cycle power block will consist of two General Electric (GE) 7FA combustion turbines/heat recovery steam generators (CT/HRSG) units and one steam turbine generator (STG). This configuration is referred to as a 2-on-1 power plant configuration with two sets of CTs, duct burners, and HRSGs connected to a single STG. Each HRSG is to be equipped with a 541.7 MMBtu/hr duct burner fired exclusively with natural gas. The combustion turbines may be operated in power augmentation mode when needed. The combustion turbines are capable of accommodating natural gas, very low sulfur fuel oil, and ultra low sulfur diesel fuel. The power output of each power block is nominally rated at 630 MWs. 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 combustion turbines are limited to 1,000 hours per year of distillate fuel oil usage.

Ancillary equipment for the expansion consists of one 2,000 hp diesel fired emergency generator, one 208 hp diesel fired emergency firewater pump, two cooling towers, two natural gas fuel heaters (each approximately 5 MMBtu/hr); one 3 million gallon distillate fuel oil tank; one 1,000 gallon diesel fuel tank; and one 300 gallons diesel fuel tank. The operational time for each diesel fired generator/pump will be limited to 500 hours.

The combustion turbines and duct burners will be equipped with dry low NOx combustors/burners for control of NOx emissions during natural gas combustion. For fuel oil combustion, the combustion turbines are equipped with water/steam injection to minimize NOx emissions. NOx emissions from the combined turbine/duct burner stack will be controlled by selective catalytic reduction post air pollution combustion control. Carbon monoxide (CO) and volatile organic compound (VOC) emissions from the combined turbine/duct burner stack will be controlled by catalytic oxidation post air pollution combustion control. The estimated potential emissions of regulated pollutants from the McIntosh Combined Cycle Facility are as follows: Particulate Matter with an aerodynamic diameter less than 10 microns (PM_{10}) = 417 tons per year; Particulate Matter (PM) = 417 tons per year; Nitrogen Oxides (NOx) = 475 tons per year; Carbon Monoxide (CO) = 219 tons per year; Sulfur Dioxide (SO_2) =238 tons per year; Volatile Organic Compounds (VOC) = 114 tons per year; Lead (Pb) = 0; Sulfuric Acid Mist (H_2SO_4) = 36. Contemporaneous reductions in sulfur dioxide emissions from Plant McIntosh are required to address Class I impacts associated with the proposed expansion. The permitting of the contemporaneous reductions is addressed through a separate permitting action.

The location of the combustion facility in Effingham County is classified as "attainment" for PM_{10}, NOx, CO, SO_2 and Ozone in accordance with Section 107 of the Clean Air Act, as amended August 1977.

The EPD review of the data submitted by the McIntosh Combined-Cycle Facility for the construction and operation of the two combined-cycle power blocks indicates that compliance with all applicable State and Federal air quality regulations will be achieved.

It is the Preliminary Determination of EPD that the proposal provides for the application of best available control technology (BACT) for the control of NOx, CO, SO_2, PM, PM10, and VOC as required by Federal PSD regulation 40 CFR 52.21(j).

It has been determined through approved modeling techniques, that the estimated emissions will not cause or contribute to a violation of any ambient air standard or allowable PSD increment. 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.

The Preliminary Determination indicates that an Air Quality Permit should be issued to the McIntosh Combined-Cycle Facility for the construction and operation of the two combined-cycle power blocks and ancillary equipment. Various conditions will be made a part of the permit to construct and operate in order to insure and confirm compliance with all applicable regulations. A copy of the draft permit is provided in Appendix A.

1.0 APPLICATION INFORMATION

Applicant Name and Address

Savannah Electric and Power Company
McIntosh Steam-Electric Generating Plant
981 Old Augusta Road
Rincon, Effingham County, Georgia 31326

Authorized Representative: Lamar O. Keller, Manager, Environmental, Safety and Health

November 8, 2001	Date of PSD Application Assigned No. 13404
November 9, 2001	Letter from Trinity Consultants(on behalf of SEPC) to Mr. Stanley Vasa Regarding Class I Modeling and AQRV Analyses
November 9, 2001	Letter from SEPC to Mr. Elwyn Rolofson of U.S. Fish and Wildlife Service – AQRV Analysis for Cape Romain, Wolf Island, and Okefenokee National Wilderness Areas
November 14, 2001	Date of Receipt of Application
November 16, 2001	Acknowledgement Letter from EPD Including List of Application Deficiencies
November 21, 2001	Letter from EPD Requesting Submittal of a Title V Permit Application for Equipment Specified in Application No. 13404
January 16, 2002	Letter from SEPC in Response to EPD Letters Dated November 16 and November 21, 2001
February 8, 2002	Letter from Trinity Consultants to Ms. Ellen Porter of U.S. Fish and Wildlife Service – Windroses from CALMET Data used in Class I Modeling
February 18, 2002	Letter from SEPC to EPD – Title V Application and Additional Information for Combined-Cycle Units.
February 20, 2002	Date of Title V Application Assigned No. 13404
March 13, 2002	Letter from Trinity Consultants to Southern Company Regarding Revised Sulfur Dioxide PSD Regional Inventory Data
March 18, 2002	Letter from SEPC to EPD Regarding Startup and Shutdown for Proposed Power Blocks
April 11, 2002	Letter from Trinity Consultants to Southern Company Services as an addendum to November 9, 2001 AQRV analysis
April 16, 2002	Letter from Southern Company Services to Ms. Ellen Porter of U.S. Fish and Wildlife Service – Updated AQRV Analysis for Cape Romain, Wolf Island, and Okefenokee National Wilderness Areas
April 18, 2002	SEPC submitted a Revised Section 5.0 of Permit Application including Revised Class I and Class II modeling analyses
April 18, 2002	Letter from SEPC to EPD Regarding EPD Questions of April 2 and April 4, 2002
April 23, 2002	Received Acid Rain Permit Application for Affected Facilities Defined in Application No. 13404 – Acid Rain Permit Application Assigned No. AR-13746
May 16, 2002	Preliminary Technical Review Document from Federal Land Manager – U.S. Fish and Wildlife Service

July 9, 2002	SEPC submitted comments to the U.S. Fish and Wildlife Service Preliminary Technical Review Document
July 16, 2002	Letter from EPD to SEPC noting results of analysis
October 3, 2002	Letter from SEPC to EPD in response to July 16th letter
October 3, 2002	Letter from SEPC to FLM as an addendum to November 9, 2001 and April 16, 2001 Class I analyses
December 4, 2002	Letter from SEPC to FLM
December 11, 2002	Letter from EPD to SEPC regarding CAM Plan
December 23, 2002	Letter from SEPC to EPD
January 23, 2003	SEPC submitted a CAM Plan

2.0 PROJECT DESCRIPTION

On November 14, 2001, Savannah Electric and Power Company – McIntosh Steam-Electric Generating Plant (a.k.a. Plant McIntosh) submitted an application for an air quality permit to construct and operate four combined-cycle combustion trains (i.e., two combined-cycle power blocks) at the existing Plant McIntosh site in Rincon, Effingham County, Georgia. Plant McIntosh consists of one nominal 177-megawatt coal-fired unit, eight nominal 80-MW simple cycle combustion turbines, and ancillary equipment. The McIntosh Combined-Cycle Facility application and supporting data for the expansion are included in Appendix B.

The Plant McIntosh expansion, referred to as the McIntosh Combined-Cycle Facility, consists of two combined-cycle power blocks. Each combined-cycle power block will consist of two General Electric (GE) 7FA combustion turbines/heat recovery steam generators (CT/HRSG) units and one steam turbine generator (STG). This configuration is referred to as a 2-on-1 power plant configuration with two sets of CTs, duct burners, and HRSGs connected to a single STG. Each HRSG is to be equipped with a 541.7 MMBtu/hr duct burner fired exclusively with natural gas. The combustion turbines may be operated in power augmentation mode when needed. The combustion turbines are capable of accommodating natural gas, very low sulfur fuel oil, and ultra low sulfur diesel fuel. The power output of each power block is nominally rated at 630 MWs. 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 combustion turbines are limited to 1,000 hours per year of distillate fuel oil usage.

Ancillary equipment for the expansion consists of one 2,000 hp diesel fired emergency generator, one 208 hp diesel fired emergency firewater pump, two cooling towers, two natural gas fuel heaters (each approximately 5 MMBtu/hr); one 3 million gallon distillate fuel oil tank; one 1,000 gallon diesel fuel tank; and one 300 gallons diesel fuel tank. The operational time for each diesel fired generator/pump will be limited to 500 hours.

Each duct burner is to be equipped with a dry low NOx burner. Each combustion turbine is to be equipped with a dry low NOx combustor for natural gas combustion and water injection for fuel oil combustion. Selective catalytic reduction post air pollution control equipment will be used to control emissions from the combined turbine and duct burner stack. Emissions of sulfur dioxide will be minimized by restricting fuel use to natural gas, very low sulfur fuel oil, and ultra low sulfur diesel fuel. Emissions of CO and VOC will be controlled by efficient combustion of the fuel and the use of catalytic oxidation post air pollution control equipment. The use of clean, low-ash fuels and efficient combustion will limit the emissions of particulate matter and lead.

Air pollutant emissions are based, in part on the following combustion turbine scenarios: (1) 1,000 hours per year of power augmentation mode during natural gas combustion; (2) 1,000 hours per year of fuel oil combustion; (3) 6,760 hours per year of non-power augmentation during natural gas combustion. Duct burner emissions are based on 8,760 hours per year. [*See Appendix B of this document for more detail on annual calculation derivation for criteria air pollutants.*] Hazardous air pollutant (HAP) emissions are taken from Chapter 3 of the application. The potential to emit of regulated air pollutants under this proposal are illustrated in Table 1. Particulate matter emissions are based on the best data currently available from the manufacturer and include both front and back half condensible particulate from the combustion turbines.

Table 1. Emissions Summary of the McIntosh Combined-Cycle Facility Expansion

Air Pollutant	Total Emissions TPY	PSD Significant Emissions Level	Is BACT Required?
CO	219	100	YES
NOx	475	40	YES
SO2	238	40	YES
PM/PM10	417	25/15	YES
VOC	114	40	YES
Lead	~0	0.60	NO
Mercury	0.01	NA	NA
H2SO4	36.57	7	YES
Acetaldehyde	1.86	NA	NA
Acrolein	0.25	NA	NA
Benzene	0.95	NA	NA
Ethyl Benzene	0.98	NA	NA
Formaldehyde	5.20	NA	NA
Naphthalene	0.27	NA	NA
PAH	0.30	NA	NA
Selenium	0.21	NA	NA
Toluene	2.93	NA	NA
Xylene	2.80	NA	NA
Total HAPs	15.75	NA	NA

Through its new source review procedure, the Division has evaluated the McIntosh Combined-Cycle Facility proposal for compliance with State and Federal requirements. The findings of the Division have been assembled in this Preliminary Determination.

3.0 REVIEW OF APPLICABLE RULES AND REGULATIONS

Georgia Rule for Air Quality Control (Georgia Rule) 391-3-1-.03(1)

Applicability: Georgia Rule 391-3-1-.03(1) requires that any person prior to beginning the construction or modification of any facility which may result in air pollution shall obtain a permit for the construction of 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)

Applicability: Georgia Rule 391-3-1-.03(8)(b) specifies 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.

Georgia Rule 391-3-1-.02(7) – Prevention of Significant Deterioration

Georgia Rule 391-3-1-.02(7) adopts by reference 40 CFR 52.21.

Georgia Rule 391-3-1-.02(2)(b) – Visible Emissions

Applicability: Georgia Rule 391-3-1-.02(2)(b) [a.k.a Georgia Rule (b)] is an applicable requirement for the combined combustion turbine and duct burner stacks and the diesel generators because said units are subject to another emission standard in Georgia Rule 391-3-1-.02(2)[i.e., Georgia Rule 391-3-1-.02(2)(g)].

Emission Standard: Georgia Rule (b) limits visible emissions to not equal or exceed forty (40) percent from said units.

Georgia Rule 391-3-1-.02(2)(d) Fuel Burning Equipment

Applicability: Georgia Rule 391-3-1-.02(2)(d) [a.k.a Georgia Rule (d)] is an applicable requirement for each fuel gas preheater and each duct burner because said units meet the definition of "fuel burning equipment" found in Georgia Rule 391-3-1-.01(cc). Georgia Rule (d)2 defines the allowable particulate matter emission rate. Georgia Rule (d)3 defines the allowable opacity limit.

Emission Standard: The allowable particulate matter emission rate for each fuel gas preheater is 0.5 pounds per million Btus in accordance with Georgia Rule (d)2(i). The allowable particulate matter emission rate for each duct burner is 0.10 lb/MMBtu. The allowable opacity limit for said units is twenty (20) percent except for one six minute period per hour of not more than twenty-seven (27) percent opacity in accordance with Georgia Rule (d)3.

Georgia Rule 391-3-1-.02(2)(g) – Sulfur Dioxide

Applicability: Georgia Rule 391-3-1-.02(2)(g) [a.k.a. Georgia Rule (g)] applies to all "fuel burning" sources. The "fuel burning" sources at the proposed site include the combustion turbines, duct burners, fuel gas heater, emergency generator, and firewater pump. Georgia Rule (g)1 applies for each combustion turbine and duct burner because the equipment has an individual heat input rate exceeding 250 MMBtu/hr and are constructed after January 1, 1972. Georgia Rule (g)2 applies for each "fuel burning" source at the proposed site.

Emission Standard: Sulfur dioxide emissions from each combustion turbine and from each duct burners shall not exceed 0.8 lbs/MMBtu of heat input derived from liquid fossil fuel in accordance with Georgia Rule 391-3-1-.02(2)(g)1. The fuel sulfur content limit for fuels burned in each combustion turbine and duct burner is 3 percent sulfur by weight in accordance with Georgia Rule 391-3-1-.02(2)(g)2 for equipment rated at 100 MMBtu/hr or greater. The fuel sulfur content limit for fuels burned in the diesel generators and fuel gas preheaters is 2.5 percent by weight in accordance with Georgia Rule (g)2 for equipment rated lower than 100 MMBtu/hr.

40 CFR 60, Subpart Da - Standard of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978

Applicability: NSPS Da is an applicable requirement for each duct burner because they each have a heat input rating greater than 250 MMBtu/hr and they are constructed after September 18, 1978.

Emission Standard: This NSPS specifies an emission standard for PM, SO_2, and NOx from each duct burner as noted in the following table:

Pollutant	Standard	Legal Authority
PM	0.03 lb/MMBtu	40 CFR 60.42a(a)(1)
Opacity	20% except for one six-minute period per hour of not more than 27 percent.	40 CFR 60.42a(b)
SO_2	0.20 lb/MMBtu on a 30-day rolling average	40 CFR 60.43a(b)(2)
NOx	1.6 lb/MW-hr, gross energy output, based on a 30-day rolling average	40 CFR 60.44a(d)(1)

40 CFR 60, Subpart GG - Standards of Performance for Stationary Gas Turbines

Applicability: NSPS GG is an applicable requirement for each combustion turbine because each combustion turbine has a nameplate capacity greater than 10 MMBtu/hr, and they are constructed after October 3, 1977. NSPS GG defines an allowable NOx and SO_2 emission rate.

Emission Standard: The allowable fuel sulfur content is 0.8 percent by weight in accordance with 40 CFR 60.333(b). The allowable NOx emission rate is specified by the following formula [40 CFR 60.332(a)(1)] because each combustion has a heat input rating greater than 100 MMBtu/hr:

$$STD = 0.0075\ (14.4/Y) + F$$

where: STD = allowable NOx emissions (% volume @ 15% O2, dry)
Y = heat rate in kilojoules per watt hour
F = fuel bound nitrogen allowance

Notes:

a) The applicant reported a heat rate (Y) of approximately 9.73 kilojoules per watt hour for natural gas combustion. The applicant notes that the value for F is 0. With this stated, the allowable NOx emission rate during natural gas combustion is approximately 111 ppmvd at 15% oxygen. The range of expected values is dependent on ambient conditions and the actual operation of the turbine.

b) The applicant reported a heat rate (Y) of approximately 11.29 kilojoules per watt hour for fuel oil combustion. The applicant notes that the value for F is 0. With this stated, the allowable NOx emission rate during fuel oil combustion is approximately 96 ppmvd at 15% oxygen. The range of expected values is dependent on ambient conditions and the actual operation of the turbine.

<u>40 CFR 60, Subpart Kb - Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984</u>

Applicability: NSPS Kb is an applicable requirement for the diesel fuel oil storage tank because the tank has a capacity greater than 40 m^3 (i.e., ~10,568 gallons), and it is constructed after July 23, 1984.

Emission Standard: No emission standard applies because the tanks are storing a material whose non-water volatile true vapor pressure is less than 2.175 psia.

Compliance Demonstration: The tanks are only subject to the record keeping requirements of 40 CFR 60.116b which requires that all storage vessels storing volatile organic liquids with a capacity equal to or greater than 40 m^3 keep readily available, for the life of the source, records showing tank dimensions, and an analysis showing the tank capacity.

<u>Federal Rule - Acid Rain Program</u>

Applicability: The Acid Rain Regulations apply to the proposed CT/HRSG units because they each have a nameplate capacity greater than $25MW_e$ and they are to supply electricity for sale, whether wholesale or retail.

According to 40 CFR 72, the modification will be designated as a Phase II Acid Rain "New Affected Unit" on January 1, 2000 or 90 days after commencement of commercial activities, whichever comes later, but not after the date the modification declares itself commercial. The McIntosh Combined-Cycle Facility has submitted their Phase II Permit Application and it is assigned application number AR-13746

Emission Standard: No SO_2 allowances are allocated up front to this modification by the Acid Rain Regulations. As such, the applicant will need to acquire SO_2 allowances in amount equal to their annual SO_2 tonnage. NOx emissions are not limited by the Acid Rain Regulation since the units are not classified as coal-fired utility boilers.

<u>**PROPOSED**- 40 CFR 63 Subpart YYYY – National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines</u>

Applicability: The combustion turbines are to be constructed at the existing Plant McIntosh facility. The proposed facility and Plant McIntosh are one site for purposes of assessing applicability for this standard because they are located on contiguous property and operate under common control. Plant McIntosh is a major source of hazardous air pollutants. Thus, each proposed combustion turbine (CT10A, CT10B, CT11A, and CT11B) will be subject to this MACT standard upon promulgation of the standard. The standard was proposed on January 14, 2003 in 68FR1888-1929. The proposed combustion turbines will be regulated as *New Stationary Turbines* because the applicant will commence construction of these units after January 14, 2003. The compliance date for the units is not defined in the proposal. The proposed revised MACT promulgation date is August 31, 2003.

Emission Standard: Based on the proposal, the applicant will need to meet one of the following emission limitations: (a) Achieve a reduction in CO of 95 percent or greater, measured before and after an oxidation catalyst emission control device is installed to treat all of the stationary combustion turbine exhaust gases, if you install an oxidation catalyst emission control device; or (b) limit the concentration of formaldehyde to 43 ppbvd or less at 15 percent oxygen, if you do not install an oxidation catalyst emission control device.

PROPOSED- 40 CFR 63 Subpart ZZZZ – National Emission Standards for Hazardous Air Pollutants for Industrial/Commercial/Institutional Boilers and Process Heaters
Applicability: The fuel gas heaters are to be constructed at the existing Plant McIntosh facility. The proposed facility and Plant McIntosh are one site for purposes of assessing applicability for this standard because they are located on contiguous property and operate under common control. Plant McIntosh is a major source of hazardous air pollutants. The fuel gas heaters meet the proposed definition of a *small process heater*. Thus, each proposed fuel gas heater (FGH1 and FGH2) will be subject to this MACT standard upon promulgation of the standard. The standard was proposed on January 13, 2003 in 68FR1660-1763. The proposed fuel gas heaters will be regulated as *New Process Heaters* because the applicant will commence construction of these units after January 13, 2003. The compliance date for the units is not defined in the proposal. The proposed revised MACT promulgation date is February 28, 2004.

Emission Standard: Based on the proposal, the fuel gas heaters would be classified as *new-small-gaseous* and thus would not be subject to an emission standard.

40 CFR 63.40 through 63.44 – Clean Air Act Section 112(g)
Applicability: The first step in the applicability determination is to identify what proposed equipment are exempt from these requirements. In the case of the proposed facility, the heat recovery steam generators (including the duct burners) are classified as *electric utility steam generating* units and thus are exempt from this subpart in accordance with 40 CFR 63 Subpart B [65FR34010-34012]. The internal combustion engines are not potentially subject to proposed 40 CFR 63 Subpart ZZZZ because each engine has a manufacturer's nameplace rating less than 500 brakehorsepower. Thus the internal combustion engines are potentially subject to 40 CFR 63 Subpart B. The combustion turbines are potentially subject to 40 CFR 63 Subpart B because they are not subject to a promulgated MACT standard. In this case, 40 CFR 63 Subpart B is applicable if the combined individual and/or total HAP emissions from the combustion turbines, internal combustion engines, and fuel gas heater(s) is equal to or greater than 10 tons of any individual HAP and 25 tons of total HAPs. The Division agrees with the applicant's findings that the new, non-exempt equipment do not generate on a combined basis potential individual HAP and total HAP emissions equal to or greater than 10 tpy and 25 tpy, respectively. Thus Clean Air Act Section 112(g) is not applicable.

40 CFR 63.50 through 63.56 – Clean Air Act Section 112(j)
Applicability: The requirements of Clean Air Act Section 112(j) apply to the combustion turbines and fuel gas preheaters if EPA fails to promulgate an emission standard under Part 63 by the section 112(j) deadline. The section 112(j) deadline is 60 days after EPA's failure to promulgate the rescheduled MACT. [*This is a proposed definition found in 67FR72875 dated December 9, 2002.*] The proposed revised Combustion Turbine MACT promulgation date is August 31, 2003 and the Part 2 Application submittal date (Section 112(j)) is October 30, 2003. The proposed revised Boiler/Process Heater MACT promulgation date is February 28, 2004 and the Part 2 Application submittal date (Section 112(j)) is April 28, 2004.

40 CFR 52.21 – Prevention of Significant Deterioration

Applicability: The McIntosh Combined-Cycle facility is to be constructed at the existing Plant McIntosh facility. The proposed facility and Plant McIntosh are one site for purposes of assessing PSD applicability because they are located on contiguous property, operate under common control, and operate under the same industrial grouping (i.e., two digit SIC code). Plant McIntosh is an existing major source under PSD. Therefore, the PSD significant emission rates apply in assessing PSD applicability. Based on the information in Table 1, the McIntosh Combined-Cycle Facility is classified as a PSD major modification for carbon monoxide, nitrogen oxides, sulfur dioxide, particulate matter, particulate matter less than 10 microns in diameter, volatile organic compounds, and sulfuric acid mist.

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

- ✓ Application of best available control technology (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
- ✓ Public notification of the proposed plant in a newspaper of general circulation.

Emission Limitation: Georgia Rule 391-3-1-.02(b)(7) incorporates and adopts by reference, among other things, the definition of BACT in 40 CFR 52.21(b)(12). BACT, as defined in 40 CFR 52.21(b)(12), means:

an emissions limitation (including a visible emission standard) 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 for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of [BACT] result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR parts 60 and 61. If the Administrator determines the technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of [BACT]. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results.

<u>State and Federal – Startup and Shutdown</u>

Startup and shutdown of the combined-cycle systems are part of *normal source operation*, and EPA requires that air permits for such facilities include (1) definitions of startup and shutdown; and (2) a mechanism to limit emissions from startup and shutdown. EPD is including definitions of cold start, warm start, hot start, and shutdown in the proposed permit and these definitions serve to allocate time for these operational scenarios. EPD is including rolling annual NOx and CO emissions limits as a mechanism to limit emissions from *normal source operation plus malfunctions* in order to limit emissions from startup and shutdown.

4.0 BACT REVIEW – COMBUSTION TURBINE/DUCT BURNER

Oxides of Nitrogen

Top-Down BACT Alternatives: The individual NOx top-down BACT alternatives considered in this study for natural gas combustion are noted from the most to least stringent: XONON™, catalytic absorption, selective catalytic reduction (SCR), and wet and dry control technology evaluation. The individual NOx top-down BACT alternatives considered in this study for fuel oil combustion are noted from the most to least stringent: catalytic absorption, selective catalytic reduction (SCR), and wet control technology evaluation.

Technical Feasibility Analysis: In catalytic combustion, a catalyst is used to promote oxidation of the inlet gas stream at lower temperatures than are required in standard thermal combustion. The catalyst bed is used to oxidize a lean air/fuel mixture within the combustor instead of burning it with a flame, as in a conventional combustor. XONON™ is a catalytic combustion system, developed by Catalytica Combustion Systems, Inc. (CCSI) for natural gas combustion. As of this review, General Electric is not yet offering the XONON™ system, or catalytic combustion, as an option on its F-class (170 MW) machines. With this in mind, the Division is unable to support setting BACT based on this emerging technology because it is not yet commercially available and therefore is not technically feasible. However, the Division will continue to monitor the availability and application of XONON and its impact on future natural gas fired turbine BACT.

Catalytic absorption is a type of post-combustion control whereby the flue gas is exhausted over a catalyst system with an absorber coating to oxidize CO to CO_2 and NO to NO_2. The SCONOx™ system, developed by Goal Line Environmental Technologies, is a proprietary precious metal oxidation catalyst system with an absorber coating. In the SCONOx™ system, the NO_2 is removed from the catalyst by passing a dilute hydrogen reducing gas across its surface. This releases the NO_2 from the surface as N_2 and H_2O. Catalytic absorption is technically feasible but is not yet commercially available for turbines of this size. However, the Division will continue to monitor the application of catalytic absorption (i.e., SCONOx™) and its impact on future combined-cycle BACT.

The use of Selective Catalytic Reduction (SCR) is technically feasible and achievable in practice for natural gas and fuel oil combustion.

The use of dry control technology, in this case, dry low NOx combustors/burners, is technically feasible and achievable in practice for the combustion turbines and duct burners fired on natural gas. Dry control technology is not yet feasible for fuel oil combustion. The use of wet control technology during natural gas combustion is technically feasible and achievable in practice; however, the use of wet control technology does not minimize emissions of NOx below that of dry control technology. Accordingly, the applicant did not choose to consider wet control technology as BACT for natural gas combustion. The use of wet control technology is technically feasible and achievable in practice for fuel oil combustion. The Division concurs with the facility's findings.

Ranking the Technically Feasible Alternatives: For natural gas combustion, SCR with ammonia injection in combination with DLN combustor/burner technology is recognized as the top control option followed by dry low-NOx (DLN) combustor technology without post air pollution control. For fuel oil combustion, SCR with ammonia injection in combination with wet control technology is recognized as the top control option followed by wet control technology without post air pollution control.

NOx BACT Emission Standard Analysis: The applicant proposed a NOx BACT limit of 3.0 ppmvd at 15% oxygen (natural gas firing-July 9, 2002) and 6 ppmvd at 15% oxygen (fuel oil firing-December 18, 2002) at the combined turbine/duct burner stack.

The lowest permitted NOx emission rate for a natural gas fired combined-cycle unit (equipped with an F-class sized combustion turbine and with supplementary duct firing) equipped with dry low NOx combustors and SCR, found by the Division, is 2.0 ppmvd at 15% oxygen. The lowest permitted NOx emission rate for a fuel oil fired combined-cycle unit (equipped with an F-class sized combustion turbine and with supplementary duct firing) equipped with water injection combustors and SCR, found by the Division, is 6.0 ppmvd at 15% oxygen.

Energy Impacts: The McIntosh Combined-Cycle Facility assumed an increase in backpressure, due to the presence of the SCR catalyst, which would reduce turbine output.

Environmental Impacts: Collateral environmental concerns evaluated were the presence of ammonia emissions; the formation of fine particulates; and the safety hazards associated with the transport, handling and storage of ammonia. The amount of NH_3 slip at any facility will theoretically begin at near zero and tend to increase over the life of the catalyst.

The presence of unreacted ammonia in the turbine exhaust could possibly react with NOx, sulfate or oxygen species to form fine particles of ammonium nitrate and/or ammonium sulfate which would primarily exist as fine particulate emissions (PM2.5). PSD regulations do not provide a mechanism to analyze the impact of PM2.5 at this time.

The use of SCR with ammonia injection requires that the proposed plant configuration include ammonia storage and handling capabilities. The applicant did not cite ammonia safety concerns as an issue that would mitigate the benefit of using SCR to control NOx emissions. This project would be subject to risk management plans under Section 112(r) of the 1990 Clean Air Act Amendments (40 CFR 68) if they store more than 10,000 pounds of anhydrous ammonia in one tank at any one time at the facility. The amount of ammonia that will be used by the project will depend on the load factor of the unit. Since both of these factors are based on future economic conditions, it is difficult to predict exactly how much ammonia will be used. This PSD preliminary determination asserts that the McIntosh Combined-Cycle Facility would achieve compliance with the Part 68 standard if this option was implemented as BACT.

Economic Impacts: No economic analysis is needed for fuel oil combustion since the applicant proposed the top level of control technically that is feasible and available for NOx emissions. The applicant's most recent economic analysis for the use of SCONOx™ and SCR during natural gas combustion is found in their October 3, 2002 letter to EPD. Pertinent information in this letter is illustrated in the following table: [*Note: The Division has included the SCONOx™ technology at the request of EPA Region IV even though this technology is not available for the size of the combined-cycle units in question.*

ECONOMIC TABLE FOR NATURAL GAS COMBUSTION

Control Option	Baseline Emissions with only DLN burners Per CT/HRSG (TPY)	Emissions with DLN burners and SCR Per CT/HRSG ppmvd	Emissions with DLN burners and SCR Per CT/HRSG (TPY)	Emission Reduction Per CT/HRSG (TPY)	Total Annualized Cost Per CT/HRSG ($)	Cost per Ton of NOx Removed Per CT/HRSG ($/ton)	Incremental Cost Effectiveness Per CT/HRSG ($/ton)
SCONOX™**	752	2.0	154	598	8,524,724	14,255	NA
SCR	475	2.5	99	376	1,279,610	3,402	4,527
SCR	475	3.0	119	356	1,189,057	3,340	4,527
SCR	475	3.5	139	336	1,098,503	3,267	-
DLN	475	Baseline (12.0)	Baseline	Baseline	Baseline	Baseline	Baseline

**Note: SCONOx™ controls NOx, CO, and VOC simultaneously. Numerical values in table represent total emission rate of NOx + CO+VOC.

NOx BACT Selection: The Division has determined that the proposal to use DLN combustor /burner technology in conjunction with SCR post-combustion air pollution control meets the requirements of BACT. The NOx BACT emission limit for natural gas combustion by the turbine is set at 2.5 ppmvd at 15% oxygen, and the NOx BACT emission limit for fuel oil combustion is set at 6 ppmvd at 15% oxygen. These BACT emission limits apply with and without duct firing. The averaging time of these emission limitations is tied to or based on the run time(s) specified by the applicable reference test method(s) or procedures required for demonstrating compliance (i.e., Method 7E – 3 hour averaging period). The Division believes that this determination is consistent with recent BACT determinations.

The annual NOx BACT emission limit is set at 113 tons per year and derivation of this emission rate can be found in Appendix B of this document. The annual NOx BACT emission limit encompasses emissions generated during normal source operation (including startup and shutdown) and malfunctions. The short term NOx BACT emission limits do not apply, in this case, during startup and shutdown periods as defined in the permit.

Carbon Monoxide and Volatile Organic Compounds

Top-Down BACT Alternatives for Carbon Monoxide and Volatile Organic Compounds: The applicant considered combustion process design and catalytic oxidation for the reduction in CO emissions. Catalytic oxidation is also effective in reducing VOC emissions. There are no applicable state or federal regulations that specify the allowable CO or VOC emission limit.

The ability of catalytic absorption (Goal Line Technologies - SCONOx™)to control CO and VOC emissions has not been demonstrated on a combined-cycle system comparable to the proposed project. Therefore, the Division has determined that it is appropriate to eliminate catalytic absorption technology (Goal Line Technologies - SCONOx™) for control of CO and VOC emissions due to availability.

Technical Feasibility Analysis: The Division considers proper combustor design and operation as technically feasible for the turbine and duct burners during natural gas and fuel oil combustion.

The Division considers the use of catalytic oxidation downstream of the duct burner in the HRSG as technically feasible for natural gas and fuel oil combustion.

Ranking the Technically Feasible Alternatives: The use of catalytic oxidation in combination with proper combustor design and operation is the most stringent control option which is technically feasible. The base case option is the use of proper combustor design and operation without end of pipe control.

CO BACT Emission Standard Analysis: The applicant has updated this portion of the application a number of times and the CO BACT proposals for natural gas firing with good combustion practice are illustrated in the following table:

	Non Power Augmentation			Power Augmentation		
Source	lb/MMBtu	lb/hr	ppm	lb/MMBtu	lb/hr	ppm
pg 4-37	0.063	153.2	31.3	-	-	-
letter of 1/16/02	0.021	50.8	-	0.041	99.6	-
letter of 4/18/02	-	-	4.0 (70%) 12.0 (30%)	-	-	18.3
letter of 10/3/02	-	22.2 (70%) 66.5(30%)	4.0 (70%) 12.0 (30%)	-	99.6	18.3

Note: where % refers to percentage of operating time

The lowest permitted CO emission rate for a natural gas fired combined-cycle unit (equipped with an F-class sized combustion turbine and supplementary duct firing) found by the Division is 2.0 ppmvd at 15% oxygen.

The applicant's CO BACT proposal during periods of fuel oil combustion is 0.069 lb/MMBtu (29.2 ppmvd at 15% oxygen and 142.7 lb/hr). They proposed good combustion practice as BACT. The lowest permitted CO emission rate for a fuel oil fired combined cycle unit (equipped with an F-class sized combustion turbine and with supplementary duct firing) found by the Division is 2.0 ppmvd at 15% oxygen.

VOC BACT Emission Standard Analysis: The applicant's VOC BACT proposal during periods of natural gas combustion is 0.011 lb/MMBtu (8.6 ppmvd at 15% oxygen and 25.2 lb/hr). They also proposed good combustion practice as BACT. The lowest permitted VOC emission rate for a natural gas fired combined-cycle unit (equipped with an F-class sized combustion turbine and supplementary duct firing) found by the Division is 2.0 ppmvd at 15% oxygen.

The applicant's VOC BACT proposal during periods of fuel oil combustion is 0.005 lb/MMBtu (3.7 ppmvd at 15% oxygen and 10.4 lb/hr). They proposed good combustion practice as BACT. The lowest permitted CO emission rate for a fuel oil fired combined cycle unit (equipped with an F-class sized combustion turbine and with supplementary duct firing) found by the Division is 2.0 ppmvd at 15% oxygen.

Energy Impacts: The applicant assumed an increase in backpressure, due to the presence of the catalytic oxidation unit, which could reduce turbine output.

Environmental Impacts: Collateral impacts from the use of catalytic oxidation could include an increase of PM emissions.

Economic Impacts: The following table specifies the applicant's economic analysis: for natural gas combustion:

Fuel Type	Source	Control Option	CO + VOC Emissions with only baseline control option Per CT/HRSG (TPY)	CO & VOC Emissions with Cat Ox and Comb Design Per CT/HRSG ppmvd	CO&+VOC Emissions with Cat Ox and Comb Design Per CT/HRSG (TPY)	Emission Reduction Per CT/HRSG (TPY)	Total Annualized Cost Per CT/HRSG ($)	Cost per Ton of CO + VOC Removed Per CT/HRSG ($/ton)
Natural Gas and Fuel Oil	letter dated 10/3/02	Cat. Ox	264	CO 2.2 VOC 2.0	78	186	862,397	4,640
Natural Gas	letter 10/3/02	Cat Ox	294	CO 2.0 VOC 2.0	75	219	862,397	3,937
Natural Gas	letter 1/16/02	Cat Ox	296	CO 2.0 VOC 2.9	88	208	820,163	3,943
Natural Gas	Orig App	Cat Ox	528	CO 6.0 VOC 3.4	190	338	736,135	2,178
Natural Gas and Fuel Oil	letter dated 10/3/02	Comb Design	264	CO 8.6 VOC 4.6	Baseline	Baseline	Baseline	Baseline
Natural Gas	letter 10/3/02	Comb Design	294	CO 7.7 VOC 8.0	Baseline	Baseline	Baseline	Baseline
Natural Gas	letter 1/16/02	Comb Design	296	CO 9.6 VOC 4.8	Baseline	Baseline	Baseline	Baseline
Natural Gas	Orig App	Comb Design	528	CO 19.4 VOC 4.8	Baseline	Baseline	Baseline	Baseline

As evident in the table, the applicant proposed several baseline emission rates. The baseline emission rates are a function of vendor data, test data, margin of compliance, and whether power augmentation and startup and shutdown are included. This table also shows that the total annualized cost (TAC) for a catalytic oxidation unit increased with each updated submittal by the applicant. The TAC values increased because (1) the catalyst life decreased from 5 years to 3 years which in turn increased the capital recovery factor for the catalyst replacement and (2) the purchased equipment costs were dynamic and showed an increase in the latest submittal.

CO and VOC BACT Selection: EPD has given careful consideration to the applicant's request that catalytic oxidation not constitute BACT and that the use of good combustion practice can achieve a CO emission limit of 4.0 ppmvd at 15% oxygen for 70% of operational time. The applicant noted that (1) the removal costs are excessive and (2) that the removal costs are excessive when compared to comparable sources already permitted by EPD. Despite the numerous updates on (1) uncontrolled CO emission rates and (2) purchased equipment costs and total annualized costs, the Division has determined that the proposed CO and VOC BACT emissions rates do not meet the requirements of BACT. The Division finds that the installation and operation of catalytic oxidation meets the requirements of BACT, in this case.

The CO and VOC BACT emission rates for natural gas firing is set at 2.0 ppmvd at 15% oxygen, each. These BACT emission rates apply for the combined CT/HRSG stack and applies with or without duct firing.

The CO and VOC BACT emission rates for fuel oil combustion in the turbine is set at 2.0 ppmvd at 15% oxygen, each. These BACT emission rates apply for the combined CT/HRSG stack with or without duct firing.

The annual CO BACT emission limit is set at 53 tons per year and derivation of this emission rate can be found in Appendix B of this document. The annual CO BACT emission limit encompasses emissions generated during normal source operation (including startup and shutdown) and malfunctions. The short term CO and VOC BACT emission limits do not apply, in this case, during startup and shutdown periods as defined in the permit.

Particulate Matter (PM/PM_{10})

Top-Down BACT Alternatives: The BACT alternatives considered by the McIntosh Combined-Cycle Facility include the use of control technologies such as cyclones, wet scrubbers, electrostatic precipitators (ESPs) and fabric filters and the use of fuels with low sulfur and low ash content coupled with air inlet cooler/filter, lube oil vent coalescer (demister) and proper combustion design and operation.

Technical Feasibility Analysis: The use of proper combustion design and operation is technically feasible. The use of fuels with low sulfur and low ash content coupled with air inlet cooler/filter and lube oil vent coalescer (demister) are technically feasible. The installation of a particulate control device on a turbine firing clean fuels is considered to be impractical, in part because CTs generate an exhaust stream with a low concentration (i.e., < 0.01 gr/acf) and small particle diameters. The Division agrees with the McIntosh Combined-Cycle Facility that the use of cyclones, wet scrubbers, electrostatic precipitators and fabric filters, in this case, is not technically feasible.

Ranking the Technically Feasible Alternatives: The only technically feasible option is the use of fuels with low sulfur and low ash coupled with air inlet cooler/filter, lube oil vent coalescer (demister) and proper combustion design and operation.

The BACT Emission Standard Analysis: Note: This BACT analysis assumes that PM emissions are equivalent to PM_{10} emissions. There are no applicable state or federal rules which specify the allowable PM or PM_{10} emission rates from the combustion turbine portion of the combined-cycle system. The heat recovery steam generator (HRSG) and duct burner constitute one piece of "fuel-burning equipment" as defined in Georgia Rule 391-3-1-.01(cc). There are no applicable federal rules which specify the allowable PM or PM_{10} emission rates from the duct burner. Georgia Rule 391-3-1-.02(2)(d)2.(iii) specifies the allowable PM emission rate from the duct burners. With a maximum heat input of 541.7 MMBtu/hr, the maximum allowable particulate matter emission rate per duct burner under Georgia Rule (d) is 0.10 lb/MMBtu.

The applicant proposed a BACT PM/PM_{10} emission rate, for natural gas combustion, from the combined combustion turbine and duct burner stack of approximately 21.5 lb/hr (0.009 lb/MMBtu) and for very low sulfur fuel oil combustion of approximately 33.9 lb/hr (0.016 lb/MMBtu).

PM/PM10 BACT Selection: Given the high combustion efficiency of the turbines and the firing of clean fuels, the PM and PM_{10} emissions should be very low. The Division has determined that the applicant's proposal to use pipeline quality natural gas and very low sulfur distillate fuel oil and/or ultra low sulfur diesel fuel, when applicable, coupled with air inlet cooler/filter, lube oil vent coalescer (demister) and proper combustion design and operation meets the requirements of BACT for PM and PM_{10}. The applicant's proposal is comparable with recently issued PSD permits in U.S. EPA Region IV. Hence, BACT for PM/PM_{10} during natural gas combustion is set at 21.5 lb/hr (0.009 lb/MMBtu) and during very low sulfur fuel oil combustion is set at 33.9 lb/hr (0.016 lb/MMBtu).

<u>Sulfur Dioxide (SO_2) and Sulfuric Acid Mist</u>

Top-Down BACT Alternatives/Technical Feasibility: The applicant considered the use of pipeline quality natural gas and very low sulfur fuel oil (i.e., sulfur content less than 0.05 weight percent) as technically feasible options. In addition, the applicant proposed an operational limit of 1,000 hours per year of very low sulfur fuel oil per combined-cycle system. The applicant used a natural gas fuel sulfur content of 0.2 grains per 100 standard cubic feet.

Based on discussions with the Federal Land Manager (U.S. Fish and Wildlife Service), BACT should also include the future use of a fuel oil whose sulfur content does not exceed 0.01 percent by weight.

Sulfur Dioxide BACT Emission Analysis: 40 CFR 60.333 [40 CFR 60, Subpart GG] limits sulfur dioxide emissions to 150 ppm or 0.8 weight percent from the combustion turbine. The combustion turbine is a "fuel-burning source" and therefore is subject to Georgia Rule 391-3-1-.02(g)2. Georgia Rule (g)2 specifies an allowable fuel sulfur content of 3.0 weight percent since the turbine and duct burner, each, has a maximum heat input greater than 100 MMBtu/hr.

No state or federal regulation specifies an allowable sulfuric acid mist emission rate. The applicant has assumed that approximately 10 percent of the sulfur dioxide emissions are oxidized to sulfur trioxide and that all of the sulfur trioxide reacts with the moisture in the stack gas to form sulfuric acid mist before exhausting to the atmosphere. The applicant noted that the highest sulfuric acid mist emission rate for natural gas combustion is 0.18 pounds per hour and for fuel oil firing is 16.5 pounds per hour.

Sulfur Dioxide and Sulfuric Acid Mist BACT Selection: The Division has determined the use of pipeline quality natural gas meets the requirements for BACT for sulfur dioxide. An excursion will be defined as any semiannual analysis which specifies a natural gas sulfur content in excess of 0.2 grains per 100 standard cubic feet.

The Division has also determined that the use of very low sulfur fuel oil whose maximum sulfur content is 0.05 weight percent meets the requirements for BACT for sulfur dioxide and sulfuric acid mist. Regarding the Federal Land Manager's request that the air permit require the future use of *ultra low sulfur diesel fuel,* EPD has investigated the availability of *ultra low sulfur diesel fuel* as compliance with 40 CFR 80 is required by June 1, 2006 for petroleum and oil refineries. It is EPD's assumption at this time, that *ultra low sulfur diesel fuel* should be available for use at the McIntosh Combined-Cycle Facility as of June 1, 2007. Thus, the permit will include a condition which requires the use of fuel oil with a maximum fuel sulfur content limit of 0.0015 weight percent (15 ppm) by June 1, 2007 absent approval by the Division for an extension of that date.

The applicant states that the need for 1,000 hours per year per system of fuel oil is due to force majure reasons arising from the use of a foreign supply of natural gas (Applicant's letter to EPD dated February 7, 2002). In addition, the applicant proposes a contemporaneous reduction in actual sulfur dioxide emissions from the existing simple cycle combustion turbines in order for the proposed expansion to achieve compliance with applicable Class I thresholds set by the Federal Land Manager. The Division has given careful consideration to the fuel oil BACT operational limit of 1,000 hours per year. This is higher than EPD has allowed in the past as EPD has typically limited fuel oil usage to 500 hours per year for a combined cycle system. Nonetheless, the applicant's proposal complies with all applicable requirements and as such EPD agrees to allow up to 1,000 hours per year per system of fuel oil usage.

6.0 CONTROL TECHNOLOGY REVIEW FOR ANCILLARY EQUIPMENT

Ancillary equipment include the following: (1) One diesel-fired emergency generator; (2) One diesel-fired emergency fire water pump; (3) Two cooling towers; (4) Two 5 MMBtu/hr natural gas fired natural gas line heaters; and (5) One 3 million gallon low sulfur distillate fuel oil storage tank; (6) One 1,000 diesel fuel storage tank; and (7) One 300 gallon diesel fuel storage tank.

Diesel Fired IC Engines

Top-Down BACT Alternatives/Technical Feasibility: The applicant considered the use of very low sulfur diesel fuel (0.2 weight percent) for SO_2 and good combustion practice coupled with an operational limit of 500 hours per year as BACT for NOx, CO, VOC, SO_2, and PM/PM_{10}. The applicant did not consider post combustion control equipment.

Technical Feasibility Analysis: Georgia Rule 391-3-1-.02(2)(g) limits the fuel sulfur content to 2.5 weight percent. Georgia Rule 391-3-1-.02(2)(b) limits the visible emissions to forty (40) percent. No state or federal regulation specifies an applicable NOx, CO, VOC, particulate matter, or visible emission standard.

The use of a catalytic converter is technically feasible; however, it is not considered further in this analysis due to the non-routine nature of the unit's operation. The applicant's proposal to use a diesel fuel with a maximum fuel sulfur content of 0.2 weight percent is technically feasible but so is the use of a diesel fuel with a maximum fuel sulfur content of 0.05 weight percent. In fact the latter fuel sulfur limit is routinely specified in comparable PSD permits issued by EPD.

BACT Selection: BACT is determined to be good combustion practice coupled with an operational limit of 500 hours per year per unit for NOx, CO, VOC, PM/PM_{10}, and visible emissions. BACT is determined to be the use of a diesel fuel with a maximum sulfur content of 0.05 weight percent and an operational limit of 500 hours per year per unit for SO_2 emissions.

This BACT conclusion is consistent with recently issued PSD permits for similar/identical facilities.

Cooling Tower

The project will include two cooling towers and EPA's publication entitled, AP-42, provides an estimate of potential emissions from the cooling tower. However, the emission estimates have very low quality ratings. The cooling tower for this project will employ high efficiency drift eliminators to control water carryover into the atmosphere and therefore reduce particulate emissions, which is the only known particulate control method. This type of design should keep drift to 0.001% of flow. This is in contrast to a default drift value of 0.02% used in the AP-42 document or a factor of 20 lower. The Division agrees with the McIntosh Combined-Cycle Facility that the drift eliminators will minimize any potential emissions from the cooling tower. Hence, the Division assumes negligible PM/PM_{10} emissions from the cooling tower and that BACT is proper design and operation. The use of drift eliminators has an established record of compliance with emission regulations and is considered BACT for similar units. The Division does not believe that the PSD permit needs to include PM/PM10 emission limits for cooling towers because of technical limitations with measuring these emissions.

Natural Gas Line Heater

A natural gas line heater may be installed as part of this expansion to condition the natural gas prior to being used in the combustion turbines. The natural gas line heater is comprised of two natural gas fired burners, each with a separate stack. The heat is directed from each burner down separate hollow tubes called "fire tubes," which transfer heat to a fluid media, which in turn transfers heat to a process coil that contains the natural gas fuel for the combustion turbines. A common heater shell contains the two fire tubes, the process coil, and the fluid media. The burners are fired as required to maintain fluid media temperature high enough to keep the natural gas at the set point temperature. Each burner can be operated independently, and the emissions from each burner exhaust through a separate stack. The heat input provided by each burner is approximately 5 MMBtu/hr and the emission unit ID Nos. for these heaters is FGH1 and FGH2.

Top-Down BACT Alternatives: The applicant did not consider the use of combustion modification or post air pollution control for said equipment. The BACT alternatives to control emissions of NOx include post-combustion control technology (selective catalytic reduction and catalytic absorption) and dry and wet control technology. The BACT alternatives to control emissions of CO and VOC include proper design and operation and catalytic oxidation. The BACT alternatives to control emissions of PM/PM_{10} is for proper design and operation and for the combustion of clean burning fuels. The BACT alternative to control emissions of SO_2 is to combust low sulfur fuels.

There are no applicable state or federal requirements which specify an allowable NOx, CO, or VOC emission rate. Georgia Rule 391-3-1-.02(2)(d)2(i) specifies the allowable PM emission rate of 0.5 lb/MMBtu heat input. Georgia Rule 391-3-1-.02(2)(d)3 specifies the allowable opacity limit of twenty (20) percent. Georgia Rule 391-3-1-.02(2)(g)2 specifies the allowable fuel sulfur content of 2.5 weight percent.

Technical Feasibility Analysis: Dry control technology and selective catalytic reduction are technically feasible for minimization of NOx emissions. Proper design and operation and catalytic oxidation are technically feasible for minimization of CO and VOC emissions. The use of low sulfur fuels for combustion is technically feasible.

BACT Emission Analysis: The applicant proposed a NOx BACT limit of 99 ppmvd at 3% oxygen (0.12 lb/MMBtu, 0.6 lbs/hr) and a CO BACT emission limit of 37.6 ppm at 15% oxygen. The following table illustrates the findings of existing emissions limits for similar/identical heaters at turbine facilities:

Facility/ Equipment	NOx Emissions	CO Emissions
Southern California Gas Co. 6.5 MMBtu/hr Non-Attainment LAER Ultra Low NOx Burner	20 ppm at 3% oxygen	50 ppm
Smarr Energy Facility 8.4 MMBtu/hr PSD Avoidance	157 ppm at 3% oxygen 1.6 lb/hr	NA
Sewell Creek Energy Facility 10.8 MMBtu/hr PSD Avoidance	122 ppm at 3% oxygen 1.6 lb/hr	NA

Economic Analysis: No economic analysis was performed by the applicant.

Energy Impacts: The application is silent on energy impacts.

Environmental Impacts: The application is silent on collateral environmental impacts.

The BACT Selection Process: Upon review, the Division finds the applicant's proposal to be acceptable. The NOx BACT emissions limit is set at 99 ppmvd at 3% oxygen. The CO BACT emissions limit is set at 37 ppmvd at 15% oxygen. The VOC, SO_2, PM, and visible emissions BACT will be set as a work practice standard, namely, that the Permittee shall only fire pipeline quality natural gas in each fuel gas heater. This BACT work practice standard will subsume the requirements of Georgia Rule 391-3-1-.02(2)(d) for PM and visible emissions and of Georgia Rule 391-3-1-.02(2)(g) for fuel sulfur content.

7.0 TESTING AND MONITORING REQUIREMENTS

<u>Combustion Turbine and Duct Burners</u>

Each combined-cycle unit is subject to BACT requirements for NOx, CO, SO_2, H_2SO_4, VOC, and PM/PM_{10} emissions and for visible emissions (opacity); and the Acid Rain Regulations for SO_2 emissions. The PSD BACT requirements subsume the requirements for fuel sulfur limits specified in Georgia Rule 391-3-1-.02(2)(g); the PM emission limit in Georgia Rule 391-3-1-.02(2)(d); and the NOx emissions and fuel sulfur content requirements in NSPS GG.

Requirements for NOx: To reasonably assure compliance with the BACT NOx emissions limitation, the Continuous Emissions Monitoring Systems (CEMS), required by the Acid Rain regulation, are required to be installed and operated to measure NOx concentration and diluent discharge to the atmosphere from each combined combustion turbine and duct burner stack. The CEMS is also used to determine the contribution of NOx emissions on an annual basis from the combined-cycle systems to verify compliance with the PSD annual NOx emission limits. This is further clarified in Part 8 of this narrative. The monitoring provisions of NSPS GG [40 CFR

60.334(c)(1)] use combustion turbine operating parameters (water-to-fuel rates and fuel nitrogen content) to identify periods of excess NOx emissions. The proposed permit will not require the installation and operation of devices to continuously monitor and record the consumption of the water to fuel ratio since the turbines are equipped with a NOx CEMS. In addition, the permit will waive the requirement of the daily monitoring of the nitrogen content of the natural gas and fuel oil as the NOx emissions will be tracked with a NOx CEMS.

An exceedance is defined as any three hour rolling average NOx emission rate, which exceeds 2.5 ppmvd at 15% oxygen (for natural gas combustion) or 6.0 ppmvd at 15% oxygen (for fuel oil combustion) for each combined combustion turbine and duct burner . Each one-hour average which comprises a three hour rolling average must be based upon at least 30 minutes of turbine operation and include at least 2 data points with each representing a 15-minute period and shall not include periods of startup or shutdown, as defined in the permit. Each clock hour begins a new one-hour average.

The testing provisions of NSPS GG [40 CFR 60.335(c)(2)] require the Permittee conduct NOx performance testing at four different loads across the unit operating range. EPA has granted a waiver of this requirement when a CEMS is used to satisfy the NOx monitoring requirements in the rule. The permit will require an initial performance test for NOx emissions from the combined turbine and duct burner stack. No annual performance testing requirement is included. Since the testing provisions in NSPS GG [40 CFR 60.335(c)(1)] requires that performance tests results be corrected to International Standards Organization (ISO) standard day conditions, CEMS results must also be expressed on this same basis in order to conclusively identify periods of exceedances. [*Note: An ISO Standard Day Condition is 288 deg Kelvin, 60 percent relative humidity and 101.3 kilopascals of pressure.*]

Requirements for CO: To reasonably assure compliance with the BACT CO emissions limitation, the proposed permit requires the installation and operation of Continuous Emissions Monitoring Systems (CEMS) to measure CO concentration and diluent discharge to the atmosphere from each combined combustion turbine and duct burner stack. The CEMS is also used to determine the contribution CO emissions on an annual basis from the combined-cycle systems to verify compliance with the PSD annual CO emission limits. This is further clarified in Part 8 of this narrative.

An exceedance is defined as any three hour rolling average CO emission rate, which exceeds 2.0 ppmvd at 15% oxygen (for natural gas and fuel oil combustion) for each combined combustion turbine and duct burner . Each one-hour average which comprises a three hour rolling average must be based upon at least 30 minutes of turbine operation and include at least 2 data points with each representing a 15-minute period and shall not include periods of startup or shutdown, as defined in the permit. Each clock hour begins a new one-hour average.

The permit includes an initial performance test on each combined combustion turbine and duct burner stack for CO emissions at base load and sixty (60) percent load to verify compliance with the CO BACT emission standard. No annual performance testing requirement is imposed.

Requirements for VOC: The permit includes an initial performance test on each combined combustion turbine and duct burner stack for VOC emissions at base load and sixty (60) percent load to verify compliance with the VOC BACT emission standard. There is no readily available method for monitoring actual VOC emissions in the stack. The Division believes that the operation of each combined-cycle system will be in compliance with the short term VOC BACT limit as long as the emissions are in compliance with the short term CO BACT emissions limit.

Requirements for Particulate Matter and Opacity: The permit includes an initial performance test on each combined combustion turbine and duct burner stack for particulate matter and visible emissions at base load and at sixty (60) percent load during fuel oil combustion. Natural gas, very low sulfur fuel oil and ultra low sulfur diesel fuel are low-ash fuels and should result in combustion which generates negligible particulate matter and visible emissions whose magnitude is less than the allowable (i.e., the likelihood of violation is minimal). Thus, no testing is prescribed for natural gas combustion and no additional periodic monitoring is prescribed during combustion of any of the allowable fuels.

Requirements of 40 CFR Part 64 – Compliance Assurance Monitoring
The proposed combined-cycle systems are to be constructed and operated at an existing Title V facility. The proposed construction and existing Title V equipment will be on contiguous property and under common control. Since the PSD/Title V applications are being processed as both a PSD application and a Part 70 Significant Modification, EPD assessed the applicability of 40 CFR Part 64.5(a)(2) which specifies the deadline for submittal of a Compliance Assurance Monitoring (CAM) plan. As noted above, EPD will require the installation and operation of NOx and CO CEMS and these form the basis of the CAM plan. It should be noted that the CEMS do not meet the Part 64.1 definition of *continuous compliance determination*. The *continuous compliance determination* method for NOx is Method 7 (or alternatively Method 7E) and for CO is Method 10. Thus the use of a NOx and CO CEMS does not fall under the exemption of Part 64.2(b)(vi).

Part 64.5(a)(2) applies, in part, to *large pollutant-specific emissions units* which comprise the proposed Part 70 Significant Modification. Also, while the combustion turbines and duct burners exhaust through common stacks, they are separate *pollutant-specific emission units* under Part 64. Based on the Part 64 definition of *large pollutant-specific emissions units*, EPD and the applicant believe that the combustion turbines meet the definition of *large pollutant-specific emissions units* for NOx and CO emissions for natural gas combustion and for NOx emissions for fuel oil combustion. In addition, EPD and the applicant believe that the duct burners meet the definition of *large pollutant-specific emission units* for NOx and CO emissions for natural gas combustion. The applicant's CAM plan is dated January 23, 2003.

<u>Ancillary Equipment</u>

Ancillary equipment includes the fuel gas heaters, emergency generator, emergency fire-water pump, cooling towers, and lube oil demister vents. The fuel gas heaters are subject to PSD BACT emission standards for NOx and CO and a PSD BACT work practice standard for SO_2, H_2SO_4, VOC, and PM/PM_{10} emissions and for visible emissions. The PSD BACT work practice standard specifies that the Permittee shall only fire pipeline quality natural gas in each fuel gas heater. No additional monitoring is prescribed to verify compliance with this standard. The permit includes an initial performance test on each fuel gas heater for NOx and CO emissions. EPD anticipates that the average tested emission rates for NOx and CO will be at the most sixty percent of the allowable based on testing of similar/identical equipment at Georgia Power-Plant Dahlberg. Thus, no additional monitoring is prescribed for NOx and CO emissions.

The diesel-fired emergency generator and emergency fire-water pump are subject to PSD work practice standards for NOx, CO, SO_2, H_2SO_4, VOC, and PM/PM_{10} emissions and for visible emissions. The work practice standards include fuel sulfur content and operational limits. Verification of compliance with the fuel sulfur limit will be tracked by obtaining fuel supplier certifications. Verification of compliance with the operational limit will be done by monitoring and recording the operational time.

The Division believes that no monitoring of emissions from the cooling towers and lube oil demister vents is necessary for PSD purposes.

8.0 OTHER RECORD KEEPING AND REPORTING REQUIREMENTS

The Permit contains general requirements for the maintenance of all records for a period of five years following the date of entry and requires the prompt reporting of all information related to deviations from the applicable requirement. Records, including identification of any excess emissions, exceedances, or excursions from the applicable monitoring triggers, the cause of such occurrence, and the corrective action taken, are required to be kept by the Permittee and reporting is required on a semiannual basis.

Verification of Compliance with the NOx Mass Emission Rate

Compliance with the twelve month rolling total NOx emission rate from each combined-cycle system is tracked using the NOx CEMS data to compute the NOx mass emission rate. The Permittee is required to maintain monthly records which specify the twelve consecutive month total NOx emissions (in tons) from each combined-cycle system. Failure to maintain NOx emissions from each combined-cycle system below 113 tons during any twelve consecutive must be reported as an exceedance.

Verification of Compliance with the CO Mass Emission Rate

Compliance with the twelve month rolling total CO emission rate from each combined-cycle system is tracked using the CO CEMS data to compute the CO mass emission rate. The Permittee is required to maintain monthly records which specify the twelve consecutive month total CO emissions (in tons) from each combined-cycle system. Failure to maintain CO emissions from each combined-cycle system below 53 tons during any twelve consecutive months, must be reported as an exceedance.

Verification of Compliance with the Fuel Sulfur Content Limits

NSPS GG [*see 40 CFR 60.334(b)(2)*] requires daily monitoring of the sulfur and nitrogen content of the fuels supplied without intermediate bulk storage [i.e., in this case, natural gas]. The Division believes that a waiver of the nitrogen monitoring requirement for natural gas is acceptable based upon the fact that NOx emissions are measured by a CEMS and because pipeline natural gas does not contain fuel-bound nitrogen that would generate NOx emissions. EPA has approved such a waiver in the past. [*See August 14, 1987 Memo – EPA Custom Fuel Monitoring Policy*].

The applicant proposes a maximum pipeline natural gas sulfur content of 0.2 grains sulfur/100 standard cubic feet. This is sufficiently lower than the NSPS GG limit of 0.8 ppm and the likelihood of violation is minimal. The Division does not believe there is anything to be gained by requiring a sulfur analysis on a schedule more frequent than semiannual. An excursion is defined as any semi-annual analysis of the sulfur content of the natural gas whose value exceeds 0.2 grains per 100 standard cubic feet.

NSPS GG [*see 40 CFR 60.334(b)(1)*] requires monitoring of the sulfur and nitrogen content of the fuel supplied from a bulk storage tank [i.e., in this case, very low sulfur fuel oil and ultra low sulfur diesel fuel, when applicable] on each occasion that fuel is transferred to the storage tank from any other source. The Division will implement an EPA approved monitoring schedule as defined in their May 26, 2000 memo [*EPA Region 4 Memo – "Approval of Routine Alternative Testing and Monitoring Procedures for Combustion Turbines Regulated Under New Source Performance Standards*]. The Permittee will have the flexibility to monitor the sulfur content using "as-delivered" samples instead of samples collected from their own storage tank. The Division believes that this method of compliance is acceptable if the sulfur content of all the fuel oil delivered meets the applicable limits by default under this scenario. EPA has provided a waiver to owners and operators of the requirements to determine the nitrogen content of the oil burned in a combustion turbine in cases where NOx emissions are monitored using a CEMS.

9.0 AMBIENT AIR QUALITY REVIEW

An air quality analysis is required of the ambient impacts associated with the construction and operation of the proposed McIntosh Combined-Cycle Facility. The main purpose of the air quality analysis is to demonstrate that emissions emitted from the proposed McIntosh Combined-Cycle Facility 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 II or Class I area. NAAQS exist for NO_2, CO, PM_{10}, SO_2, Ozone (O_3), and lead (P_b). PSD increments exist for SO_2, NO_2, and PM_{10}.

Generally, the source impact analysis will involve (1) an assessment of existing air quality, which may include ambient monitoring data and air quality dispersion modeling results; and (2) predictions, using dispersion modeling, of ambient concentrations that will result from the proposed plant and future growth associated with the project.

The following three Class I areas are located within 200 km of the proposed project: (1) Cape Romain National Wildlife Refuge at 155 km; (2) Wolf Island National Wildlife Refuge at 109 km; and (3) Okefenokee National Wildlife Refuge at 174 km in distance from the proposed plant. The U.S. Fish and Wildlife Service is designated as the Federal Land Manager for these Class I areas.

A separate air quality analysis is required for each of these pollutants to be emitted in an amount over the PSD significant threshold. As shown in Table 1, CO, NOx, SO_2, PM/PM_{10}, Sulfuric Acid Mist, and VOC are to be emitted in amounts over their respective PSD significant thresholds.

The following tables illustrate the Class II modeling results:

Class II Modeling Results Natural Gas Plus Fuel Oil Combustion Application Pages 5-8 and 5-9, April 19, 2002 Edition

Pollutant	Averaging Period	Preconstruction Monitoring Evaluation (ug/m^3)	Class II PSD Modeling Significant Impact Level (ug/m^3)	Projected Concentration (ug/m^3)
CO	8 hour 1 hour	575 No 1 hour	500 2,000	64 142
NO_2	Annual	14	1	0.25
PM_{10}	Annual 24 hour	No annual 10	1 5	0.13 4.8
SO_2	Annual 24 hour 3 hour	No annual 13 No 3 hour	1 5 25	0.28 13.1 35.9
VOC	No significant air quality concentration for ozone monitoring has been established. Instead, applicants with a net emissions increase of 100 tons per year or more of VOCs subject to PSD would be required to perform an ambient impact analysis, including pre-application monitoring data			

As shown in the table above, the impacts for CO, PM_{10} and NOx are below the de minimis preconstruction monitoring concentrations; therefore, preconstruction air quality monitoring is not required for these pollutants. The SO_2 impact is slightly above the de minimis concentration; however, EPD will accept data from the Farmers Market, Savannah monitoring station in lieu of further SO_2 monitoring. Furthermore, the proposed expansion has the potential to emit more than 100 tons per year of VOC; however, EPD will accept ozone data from the Savannah-Beaufort monitoring station in lieu of further ozone monitoring.

The modeling significant impact level was exceeded for the 3- and 24-hour SO_2 and so the applicant conducted a National Ambient Air Quality Standard (NAAQS) and PSD increment analyses. EPD reviewed the applicant's NAAQS and PSD increment analyses and agrees with the applicant's findings. The proposed expansion complies with the NAAQS and PSD Increment requirements of 40 CFR 52.21. The following table illustrates the results of the NAAQS and PSD increment analyses:

Class II Modeling Results-NAAQS and PSD Increment Analyses Natural Gas Plus Fuel Oil Combustion Application Page 5-19, April 18, 2002 Edition					
Pollutant	Averaging Period	NAAQS Standard (ug/m^3)	Total Concentration (ug/m^3)	Class II PSD Increment (ug/m^3)	Maximum Predicted Impact (ug/m^3)
SO_2	24 hour 3 hour	365 1300	244 756	91 512	65 253

Effingham County, where the proposed expansion would be located, is currently in compliance with the 1-hour ozone standard. There are ongoing actions by both EPD and U.S. EPA that are expected to result in reductions in ozone in Effingham County. These include the NOx SIP Call, national lower sulfur gasoline and diesel fuel, and lower emission standards on both off-road and on-road vehicles. EPD does not expect the project to cause or contribute to a violation of the ozone NAAQS.

The applicant submitted an initial Class I impact analysis on November 9, 2001 and an updated submittal on April 16, 2002. The Class I impact analysis covered PSD Class I increments, visibility, and total sulfur and total nitrogen deposition. This work showed that with natural gas combustion alone, the proposed project would comply with all requirements, including increments, visibility, and total sulfur and total nitrogen deposition at the three Class I areas. For fuel oil combustion, this work also demonstrated compliance with the increments for NOx and PM_{10} and with total sulfur and total nitrogen deposition. The applicant's November 9, 2001 and April 16, 2002 analyses showed problems with two class I area issues: SO_2 increments and visibility impacts at Cape Romain and Wolf Island. This is highlighted in EPD's review in Appendix C. The applicant resolved these issues and submitted an updated analysis dated October 3, 2002. As part of this resolution, the applicant committed to utilizing a lower sulfur fuel oil in the existing simple cycle combustion turbines at Plant McIntosh. The baseline average fuel oil sulfur content for these simple cycle combustion turbines is 0.18 percent by weight. The applicant determined that a lower fuel oil sulfur content is needed to ensure compliance with the Class I visibility requirements of the FLM. The applicant has committed to utilizing a fuel oil with a maximum sulfur content of 0.05 weight percent in the existing eight simple cycle combustion turbines at or before startup of the four combined-cycle systems. The permitting action to incorporate a lower fuel oil sulfur content limit for the existing simple cycle turbines will be handled in a separate permitting action. The FLM has reviewed the applicant's October 3, 2002 submittal and has verbally approved the method of resolution and outcome.

The following table illustrates the Class I Modeling analyses results. It should be noted that the tables specify the allowable Class I Increment and the proposed EPA modeling Class I significant level. The projected concentrations were only compared to the allowable increments in order to verify compliance with the Class I Increments.

Class I Modeling Results-Cape Romain Natural Gas Combustion (8760 hrs/yr) April 11, 2002, Table 4				
Pollutant	Averaging Period	Proposed EPA Modeling Class I Significant Level (ug/m^3)	Allowable Increment (ug/m^3)	Projected Concentration (ug/m^3)
NO_2	Annual	0.1	2.5	0.00
PM_{10}	Annual 24 hour	0.2 0.3	5 10	0.00 0.063
SO_2	Annual 24 hour 3 hour	0.1 0.2 1.0	2 5 25	0.0 0.003 0.01

Class I Modeling Results-Cape Romain Fuel Oil Combustion (1000 hrs/yr) April 11, 2002 and October 3, 2002				
Pollutant	Averaging Period	Proposed EPA Modeling Class I Significant Level (ug/m^3)	Allowable Increment (ug/m^3)	Projected Concentration (ug/m^3)
NO_2	Annual	0.1	2.5	0.00265
PM_{10}	Annual 24 hour	0.2 0.3	5 10	0.00482 0.09
SO_2	Annual 24 hour 3 hour	0.1 0.2 1.0	2 5 25	0.00 4.3 14.2

Class I Modeling Results-Wolf Island Natural Gas Combustion (8760 hrs/yr) April 11, 2002, Table 4				
Pollutant	Averaging Period	Proposed EPA Modeling Class I Significant Level (ug/m^3)	Allowable Increment (ug/m^3)	Projected Concentration (ug/m^3)
NO_2	Annual	0.1	2.5	0.00
PM_{10}	Annual 24 hour	0.2 0.3	5 10	0.00 0.126
SO_2	Annual 24 hour 3 hour	0.1 0.2 1.0	2 5 25	0.00 0.007 0.021

Class I Modeling Results-Wolf Island Fuel Oil Combustion (1000 hrs/yr) April 11, 2002 and October 3, 2002				
Pollutant	Averaging Period	Proposed EPA Modeling Class I Significant Level (ug/m^3)	Allowable Increment (ug/m^3)	Projected Concentration (ug/m^3)
NO_2	Annual	0.1	2.5	0.00185
PM_{10}	Annual 24 hour	0.2 0.3	5 10	0.00386 0.15

Class I Modeling Results-Wolf Island Fuel Oil Combustion (1000 hrs/yr) April 11, 2002 and October 3, 2002				
Pollutant	Averaging Period	Proposed EPA Modeling Class I Significant Level (ug/m^3)	Allowable Increment (ug/m^3)	Projected Concentration (ug/m^3)
SO_2	Annual 24 hour 3 hour	0.1 0.2 1.0	2 5 25	0.02 4.1 21.8

Class I Modeling Results-Okefenokee Natural Gas Combustion (8760 hrs/yr) April 11, 2002, Table 4				
Pollutant	Averaging Period	Proposed EPA Modeling Class I Significant Level (ug/m^3)	Allowable Increment (ug/m^3)	Projected Concentration (ug/m^3)
NO_2	Annual	0.1	2.5	0.00
PM_{10}	Annual 24 hour	0.2 0.3	5 10	0.00 0.05
SO_2	Annual 24 hour 3 hour	0.1 0.2 1.0	2 5 25	0.00 0.002 0.007

Class I Modeling Results-Okefenokee Fuel Oil Combustion (1000 hrs/yr) April 11, 2002 and October 3, 2002				
Pollutant	Averaging Period	Proposed EPA Modeling Class I Significant Level (ug/m^3)	Allowable Increment (ug/m^3)	Projected Concentration (ug/m^3)
NO_2	Annual	0.1	2.5	0.000774
PM_{10}	Annual 24 hour	0.2 0.3	5 10	0.000774 0.08
SO_2	Annual 24 hour 3 hour	0.1 0.2 1.0	2 5 25	0.000762 0.17 0.43

Class II Visibility Analysis: The applicant conducted a visibility analysis on nearby highways, airports, and state parks. The Savannah airport (approximately 24 km from site), highway 311 (7 km from site), and Interstate 95 (12 km from site) were the impact sites of interest. The applicant determined that there are two near-distance-visibility-related issues of potential concern due to the proposed expansion. These are the effects of particulates emitted from 1) the combustion process and 2) evaporation of the condensed cooling tower plumes. The applicant presented the results of the analyses on pages 5-21 through 5-23 (original application) and the results show that the VISCREEN screening criteria are not exceeded.

Class I AQRV Analysis: The applicant conducted an air quality related value (AQRV) analysis to assess the potential risk to AQRVs at the Cape Romain National Wilderness Area (NWA), the Wolf Island NWA, and the Okefenokee NWA. The applicant analyzed the project effects on visibility and sulfur and nitrogen deposition.

The applicant conducted the deposition analysis using the worst-case long-term emission rates from combustion of both natural gas and fuel oil with a maximum fuel sulfur content of 0.05 weight percent. According to the FLM report dated May 10, 2002, the project is not expected to contribute significantly to deposition at the applicable Class I areas (i.e., predicted impact less than 0.01 kg/hectare/yr).

Regarding the visibility analysis, the FLM recommends that a 5% change in light extinction by an individual source be considered significant. The applicant's most recent Class I visibility analysis is found in their October 3, 2002 letter to EPD. The following table illustrates the applicant's findings:

Class I Area	Maximum Visibility Impact (%) (RH=98%)	Number Days > 5% (RH=98%)
Cape Romain	0.65	0
Wolf Island	2.6	0
Okefenokee	4.6	0

As shown in this table, the maximum visibility impacts (at a relative humidity of 98%) are below the 5% FLAG threshold. The applicant's analyses achieved this outcome by 1) using a CALPUFF run for new project source with 3 km resolution grid, 2) using a reduced sulfur content of fuel oil for existing simple cycle combustion turbines from 0.18% to 0.05%, and 3) using refined parameters for sea salt contribution, ammonia contribution, fog contribution, and Rayleigh scattering coefficient.

Georgia Air Toxics Guideline: There are no applicable NAAQS or specific Georgia ambient air standards for the non-criteria pollutants listed in Table 1. Impacts from each of the pollutants listed in this letter were analyzed using the Division Guidance for Ambient Impact Assessment of Toxic Air Pollutant Emissions (referred to as the Georgia Air Toxics Guideline; Version June 21, 1998). The Georgia Air Toxics Guideline is a guide for estimating the environmental impact of sources of toxic air pollutants. A toxic air pollutant is defined as any substance which may have an adverse effect on public health, excluding any specific substance that is covered by a State or Federal ambient air quality standard. The ISCST3 computer dispersion model was used to predict the maximum 24-hour and 15-minute average ground level concentration (referred to as MGLC) for each pollutant in question.

Each MGLC is compared to its respective acceptable ambient concentration (referred to as AAC). The basis for calculation of the AAC comes from the pollutant toxicity rating systems described in the Georgia Air Toxics Guideline. Based on the Division's analysis, the predicted MGLC's for each applicable pollutant is below the AACs. A copy of this assessment is provided in Appendix C of this document.

The project also is subject to an additional impacts analysis that assesses the impacts of air pollution on soils and vegetation caused by emissions of regulated pollutants from the project, and from associated growth in the project vicinity.

10.0 ADDITIONAL IMPACT ANALYSES

General

PSD requires an analysis of impairment to visibility, soils, and vegetation that will occur as a result of the facility and an analysis of the air quality impact projected for the area as a result of 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 which are outside the PSD permitting 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 oxides – absorb or scatter light. This light scattering or absorption actually reduces the amount of light received from viewed objects and scatters ambient light into the line of sight. This scattered ambient light appears as haze.

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

Class I and Class II visibility analyses were presented earlier in this document.

Soils and Vegetation

The ambient impacts modeling analysis demonstrated that the projected impacts are below the applicable NAAQS. The applicant does not anticipate any significant impacts on soils and vegetation as a result of this proposed project.

Growth

The applicant provided a growth analysis in Part 6.1 of Permit Application No. 13404. The applicant indicates that there will be no significant growth-related air pollution impacts associated with construction and operation of the proposed expansion.

11.0 EXPLANATION OF DRAFT PERMIT CONDITIONS

The applicant has named the proposed combined-cycle facility as the McIntosh Combined Cycle Facility and the Parent Company is Southern Power Company. Thus, the proposed expansion will be permitted under a different facility name from the McIntosh Steam-Electric Generating Plant. The McIntosh Combined-Cycle Facility and the McIntosh Steam-Electric Generating Plant are one site for Title I and Title V. The expansion is taking place at an existing Title V site and so the proposed construction and operation of the expansion will be processed as a combined PSD/Title V permit.

Sections 1.1 through 1.3 define the facility. Condition 3.1 defines the emission units that are part of the PSD analysis. The facility obligations as to timelines for the commencement of construction and completion of construction, in accordance with 40 CFR 52.21(r) are specified in Condition Nos. 3.3.1 and 3.3.2. The best available control technology (BACT) requirements are specified in Condition Nos. 3.3.3 through 3.3.24. The General Testing requirements are specified in Condition Nos. 4.1.1 through 4.1.3. The specific testing requirements are specified in Condition Nos. 4.2.1 through 4.2.4. Monitoring requirements are specified in Condition Nos. 5.1.1, 5.2.1 through 5.2.10. The general record keeping and reporting requirements are specified in Condition Nos. 6.1.1 through 6.1.7. The specific record keeping requirements are specified in Condition Nos. 6.2.1 through 6.2.15. The specific reporting requirements are specified in Condition Nos. 6.2.16 through 6.2.19. The Acid Rain Requirements are specified in Condition 7.9 and Attachment D.

APPENDIX A - Draft PSD Permit

APPENDIX B - PSD Permit Application No. 13404 and Supporting Data

November 8, 2001	Date of PSD Application Assigned No. 13404
November 9, 2001	Letter from Trinity Consultants(on behalf of SEPC) to Mr. Stanley Vasa Regarding Class I Modeling and AQRV Analyses
November 9, 2001	Letter from SEPC to Mr. Elwyn Rolofson of U.S. Fish and Wildlife Service – AQRV Analysis for Cape Romain, Wolf Island, and Okefenokee National Wilderness Areas
November 14, 2001	Date of Receipt of Application
November 16, 2001	Acknowledgement Letter from EPD Including List of Application Deficiencies
November 21, 2001	Letter from EPD Requesting Submittal of a Title V Permit Application for Equipment Specified in Application No. 13404
January 16, 2002	Letter from SEPC in Response to EPD Letters Dated November 16 and November 21, 2001
February 8, 2002	Letter from Trinity Consultants to Ms. Ellen Porter of U.S. Fish and Wildlife Service – Windroses from CALMET Data used in Class I Modeling
February 18, 2002	Letter from SEPC to EPD – Title V Application and Additional Information for Combined-Cycle Units.
February 20, 2002	Date of Title V Application Assigned No. 13404
March 13, 2002	Letter from Trinity Consultants to Southern Company Regarding Revised Sulfur Dioxide PSD Regional Inventory Data
March 18, 2002	Letter from SEPC to EPD Regarding Startup and Shutdown for Proposed Power Blocks
April 11, 2002	Letter from Trinity Consultants to Southern Company Services as an addendum to November 9, 2001 AQRV analysis
April 16, 2002	Letter from Southern Company Services to Ms. Ellen Porter of U.S. Fish and Wildlife Service – Updated AQRV Analysis for Cape Romain, Wolf Island, and Okefenokee National Wilderness Areas
April 18, 2002	SEPC submitted a Revised Section 5.0 of Permit Application including Revised Class I and Class II modeling analyses
April 18, 2002	Letter from SEPC to EPD Regarding EPD Questions of April 2 and April 4, 2002
April 23, 2002	Received Acid Rain Permit Application for Affected Facilities Defined in Application No. 13404 – Acid Rain Permit Application Assigned No. AR-13746
May 16, 2002	Preliminary Technical Review Document from Federal Land Manager – U.S. Fish and Wildlife Service
July 9, 2002	SEPC submitted comments to the U.S. Fish and Wildlife Service Preliminary Technical Review Document
July 16, 2002	Letter from EPD to SEPC noting results of analysis
October 3, 2002	Letter from SEPC to EPD in response to July 16th letter
October 3, 2002	Letter from SEPC to FLM as an addendum to November 9, 2001 and April 16, 2001 Class I analyses
December 4, 2002	Letter from SEPC to FLM
December 11, 2002	Letter from EPD to SEPC regarding CAM Plan
December 23, 2002	Letter from SEPC to EPD

January 23, 2003	SEPC submitted a CAM Plan

DERIVATION OF EMISSION RATES

Plant McIntosh Expansion

DLN+SCR+Catalytic Oxidation

Pollutant	PA Emissions lb/MMBtu	PA hrs/yr	PA Heat Input MMBtu/hr	PA Emissions lb/hr	Non PA Gas Emissions lb/MMBtu	Non PA Gas hrs/yr	Non-PA Gas Heat Input MMBtu/hr	Non PA Gas Emissions lb/hr	Non PA Fuel Oil Emissions lb/MMBtu	Non PA Fuel Oil hrs/yr	Non-PA Fuel Oil Heat Input MMBtu/hr	Non PA Fuel Oil Emissions lb/hr	Wt Avg Emission CT lb/hr
NOx	0.0092	1000	1743.1	16.04	0.0092	6760	1914.4	17.61	0.0233	1000	2067.6	48.18	20.92
CO	0.00448	1000	1743.1	7.81	0.0045	6760	1914.4	8.58	0.0087	1000	2067.6	17.99	9.56
VOC	0.0026	1000	1743.1	4.53	0.0026	6760	1914.4	4.98	0.0029	1000	2067.6	6.00	5.04
PM/PM10	0.009	1000	1743.1	15.69	0.0090	6760	1914.4	17.23	0.016	1000	2067.6	33.08	18.86
SO2	0.0006	1000	1743.1	1.05	0.0006	6760	1914.4	1.15	0.0518	1000	2067.6	107.10	13.23

Pollutant	DB Emissions lb/MMBtu	DB hrs/yr	DB Heat Input MMBtu/hr	DB Emissions lb/hr
NOx	0.0092	8760	541.7	4.98
CO	0.00448	8760	541.7	2.43
VOC	0.0026	8760	541.7	1.41
PM/PM10	0.009	8760	541.7	4.88
SO2	0.0006	8760	541.7	0.33

PA=Power Augmentation Mode, natural gas firing only

Data for lb/MMBtu are based on draft BACT limits and equations found in Table D-3 footnote of SEPC letter dated Sept 2002

Data for heat input taken from Table D-3, September 2002-Revised

Data for IC Engines taken from Appendix C of Original Application

Data for Fuel Gas Heaters taken from Attachment 4, SEPC letter dated January 16, 2002

Wt Avg Wt Avg Wt Avg Wt Avg

Pollutant	Emissions CT lb/hr	DB Emissions lb/hr	Emissions CT+DB lb/hr	Emissions CT+DB tpy	Emissions 4CTs + 4DBs tpy	Emergency Generator tpy	Pump tpy	Fuel Gas Heater tpy	Facility Total tpy
NOx	20.92	4.98	25.91	113.46	453.9	12	4.8	4.38	475.0
CO	9.56	2.43	11.99	52.52	210.1	2.8	2.9	3.62	219.4
VOC	5.04	1.41	6.45	28.26	113.0	0.3	1.2	0.24	114.8
PM/PM10	18.86	4.88	23.74	103.97	415.9	0.4	0.3	0.34	416.9
SO2	13.23	0.33	13.56	59.38	237.5	0.2	0.17	0.026	237.9

APPENDIX C- Supporting Data for Dispersion Modeling