Prevention of Significant Air Quality Deterioration Review

Preliminary Determination

March, 2012
Facility Name: Effingham County Power Plant
City: Rincon
County: Effingham
AIRS Number: 04-13-10300012
Application Number(PSD, Acid Rain & Title V): 19810
Date Application Received: July 27, 2010

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

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SUMMARY

The Environmental Protection Division (EPD) has reviewed the application submitted by Effingham County Power Plant for a permit to construct and operate an additional nominal net 668-megawatt (MW) combined cycle power generation facility at their existing power plant in Effingham County, Georgia. The proposed project will consist of two combustion turbines (CTs) and associated heat recovery steam generators (HRSGs) including duct burners, one steam turbine, one fuel heater, one auxiliary boiler, one 10-cell mechanical draft cooling tower, one six-cell mechanical draft cooling tower and one fuel oil storage tank. The combustion turbines will be capable of accommodating natural gas and ultra low sulfur distillate fuel oil. The duct burners, fuel heater, and auxiliary boiler will be capable of accommodating natural gas only.

The existing Effingham County Power Plant is a major source under the Prevention of Significant Deterioration (PSD) regulation. The proposed project is classified as a major PSD modification to an existing PSD major source. The modification of the Effingham County Power Plant will result in an emissions increase in carbon monoxide (CO), nitrogen oxides (NO_x), Particulate Matter (PM), Particulate Matter with an aerodynamic diameter of ten microns or less (PM_{10}), Particulate Matter with an aerodynamic diameter of 2.5 microns or less ($PM_{2.5}$), sulfur dioxide (SO_2), Volatile Organic Compounds (VOCs), and Hazardous Air Pollutants (HAPs), and greenhouse gases (GHGs). A Prevention of Significant Deterioration (PSD) analysis was performed for this project for all regulated NSR pollutants to determine if any increase was above the PSD "significance" level. The CO, NO_x, PM, PM_{10}, $PM_{2.5}$, VOCs, and GHG emissions increases were above the applicable PSD significant emission rate threshold.

The Effingham County Power Plant is located in Effingham County, which is classified as "attainment" or "unclassifiable" for SO_2, $PM_{2.5}$ and PM_{10}, NO_2, CO, and ozone (VOC).

The EPD review of the data submitted by Effingham County Power Plant related to the proposed modification indicates that the project will be in compliance with all applicable state and federal air quality regulations.

It is the preliminary determination of the EPD that the proposal provides for the application of Best Available Control Technology (BACT) for the control of CO, NO_x, PM, PM_{10}, $PM_{2.5}$, VOCs, and GHGs, as required by federal PSD regulation 40 CFR 52.21(j).

It has been determined through approved modeling techniques that the estimated emissions will not cause or contribute to a violation of any ambient air standard or allowable PSD increment in the area surrounding the facility or in Class I areas located within 300 km of the facility. It has further been determined that the proposal will not cause impairment of visibility or detrimental effects on soils or vegetation. Any air quality impacts produced by project-related growth should be inconsequential.

This Preliminary Determination concludes that an Air Quality Permit should be issued to Effingham County Power Plant for the modification necessary to construct and operate an additional nominal net 668-megawatt (MW) combined cycle power generation facility at the existing Effingham County Power Plant. Various conditions have been incorporated into the current Title V operating permit to ensure and confirm compliance with all applicable air quality regulations. A copy of the draft permit amendment is included in Appendix A. This Preliminary Determination also acts as a narrative for the Title V Permit.

1.0 INTRODUCTION – FACILITY INFORMATION AND EMISSIONS DATA

Effingham County Power, LLC submitted a PSD application for an expansion of their facility located at 3440 McCall Road in Rincon, Effingham County, Georgia. The application was received on July 27, 2010. The application was found to be deficient upon submittal and the applicant resolved all of the deficiencies by July 3, 2011. Table 1-1 specifies the application date, application addendum dates, and associated Georgia EPD correspondence that comprise the PSD application record for this application number:

Date	Description
7/22/2010	Submittal of Initial PSD Application
7/28/2010	EPD Acknowledgement Letter
9/10/2010	Letter from Georgia EPD to Applicant to address application deficiencies
10/6/2010	Email from Georgia EPD to Applicant regarding dispersion modeling
10/13/2010	E-mail from Applicant to Georgia EPD regarding potential carbon dioxide emissions from proposed modification.
10/13/2010	E-mail from Georgia EPD to Applicant regarding startup/shutdown operational scenario on fuel oil
11/15/2010	Letter from Georgia EPD to Applicant to address application deficiencies
11/22/2010	E-mail from Applicant to Georgia EPD regarding GHG emissions.
12/01/2011	Letter from Applicant to Georgia EPD
1/25/2011	Letter from Georgia EPD to Applicant addressing CO BACT for combustion turbines
2/2/2011	Conference call between Applicant and Georgia EPD regarding 1-hour NO_2 PSD modeling Documented in an e-mail to applicant dated February 8, 2011.
3/22/2011	Letter from Applicant to Georgia EPD regarding Georgia EPD letters dated 11/15/2010 and 1/25/2011.
4/29/2011	E-mail from Georgia EPD to Applicant addressing questions about off-site emissions inventory used in PSD refined dispersion modeling.
5/6/2011	Applicant's email response to Georgia EPD's e-mail dated 4/29/2011
5/11/2011	E-mail from Georgia EPD to Applicant addressing questions about off-site emissions inventory used in PSD refined dispersion modeling
5/12/2011	Applicant's e-mail response to Georgia EPD's e-mail dated 5/11/2011
5/13/2011	E-mail from Georgia EPD to Applicant regarding 1-hour NO_2 PSD modeling
5/27/2011	E-mail from Applicant to Georgia EPD addressing Georgia EPD's question dated 5/13/2011.
6/3/2011	Letter from Applicant to Georgia EPD addressing Georgia EPD's letter dated 11/25/2011.
6/7/2011	Letter from EPA Region 4 to Georgia EPD regarding Effingham County Power's PSD application.
6/22/2011	Letter from EPA Region 4 to Georgia EPD regarding Effingham County Power's PSD application.
7/1/2011	Letter from Applicant to Georgia EPD addressing Georgia EPD's 11/25/2010 letter.

Date	Description
7/26/2011	Application update addressing GHG BACT from auxiliary equipment.
8/3/2011	Letter from Applicant to Georgia EPD addressing EPA Region 4's questions as dated 6/7/2011 and 6/22/2011

Title V Applicability

Table 1-2 specifies the Title V Major source status of the facility upon installation and operation of the proposed project.

Table 1-2: Title V Major Source Status

Pollutant	Is the Pollutant Emitted?	If emitted, what is the facility's Title V status for the Pollutant?		
		Major Source Status	Major Source Requesting SM Status	Non-Major Source Status
PM	Yes	✓		
PM_{10}	Yes	✓		
SO_2	Yes	✓		
VOC	Yes	✓		
NO_x	Yes	✓		
CO	Yes	✓		
TRS	n/a			✓
H_2S	n/a			✓
Individual HAP	Yes			✓
Total HAPs	Yes			✓

Table 1-3 below lists all current Title V permits, all amendments, 502(b)(10) changes, and off-permit changes, issued to the facility, based on a review of the "Permit" file(s) on the facility found in the Air Branch office.

Table 1-3: List of Current Permits, Amendments, and Off-Permit Changes

Permit Number and/or Off-Permit Change	Date of Issuance/ Effectiveness	Purpose of Issuance
4911-103-0012-V-04-0	February 24, 2011	Title V Renewal

PSD Applicability Analysis

The proposed modification to the Effingham County Power Plant involves the construction and operation of new emission units. A project is a major modification for a regulated NSR pollutant if it causes two types of emissions increases – a significant emissions increase and a significant net emissions increases. A significant emissions increase of a regulated NSR pollutant for construction of a new emissions unit is projected to occur if the sum of the difference between the potential to emit (as defined in 40 CFR Part 52.21(b)(4)) from each new emissions unit following completion of the project and the baseline actual emissions of these units before the project equals or exceeds the significant amount for that pollutant (as defined in 40 CFR Part 52.21(b)(23)).

Emissions of regulated NSR pollutants are based, in part on the following combustion turbine scenarios: (1) 1,000 hours per year of ultra low fuel oil combustion per CT including startup and shutdown; (2) 4,000 hours per year of duct burner operation per duct burner; (3) 1,099 hrs/yr of startup/shutdown operation per combustion turbine; (4) 2,500 hours per year of operation for new auxiliary boiler AB2; (5) sulfur content limit of natural gas is 0.5 grains per 100 standard cubic feet; and (6) sulfur content limit of fuel oil is 15 ppm. Based on the proposed project description and data provided in the permit application, the estimated incremental increases of regulated pollutants from the facility are listed in Table 1-4 below:

Table 1-4: Emissions Increases from the Project

Pollutant	Potential Emissions Increase (tpy)	PSD Significant Emission Rate (tpy)	Subject to PSD Review
PM[1]	112.3	25	Yes
PM_{10}[1]	111.4	15	Yes
$PM_{2.5}$[1]	108.7	10	Yes
VOC[1]	46.3	40	Yes
NO_x[1]	282.3	40	Yes
CO[1]	537.1	100	Yes
SO_2[1]	25.3	40	No
TRS[2]	-	10	NA
Pb[3]	0.03	0.6	No
Fluorides[2]	-	3	NA
H_2S[2]	-	10	NA
GHGs[4]	2,201,741	0	Yes
SAM[3]	4.5	7	No

[1]As provided in Georgia SIP Application Form 1.00 of Application 19810.
[2]Emissions of this pollutant are not included in Application 19810.
[3]As provided in Table 1-1 in Application 19810.
[4]As CO_{2e} in metric tons as provided in November 22, 2010 Submittal from Effingham County Power, LLC converted to short tons. As the potential to emit is greater than 75,000 tons per year, CO_{2e} is a regulated NSR pollutant.

Based on the information presented in Table 1-4 above, Effingham's proposed modification, as specified per Application No. 19810, is classified as a major modification under PSD because the potential emissions of PM, PM_{10}, $PM_{2.5}$, NO_x, CO, GHGs, and VOC exceed the PSD significant emissions rate thresholds. The net emissions increase for the project is equivalent to the potential emissions from the project as there are no contemporaneous projects to be considered in the net emissions increase analysis.

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

2.0 PROCESS DESCRIPTION

According to Application No. 19810, Effingham has proposed to permit to construct and operate an additional nominal net 668-megawatt (MW) combined cycle power generation facility at their existing power plant in Effingham County. The proposed project will add a second power block which will be a mirror image of the existing power block. The new power block will consist of two nominal 180-MW General Electric (GE) 7FAs that will operate in combined cycle mode, two heat recovery steam generators (HRSG) with each HRSG equipped with a direct-fired 470 MMBtu/hr natural gas fired duct burner, one nominal 325 MW steam turbine generator (STG), one 17.0 MMBtu/hr natural gas fired auxiliary boiler, one 8.75 MMBtu/hr natural gas fired fuel heater, a 10-cell mechanical draft cooling tower, a 6-cell cooling tower, and a fuel oil storage tank.

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 NOx emissions from each combined turbine and duct burner stack. Emissions of CO and VOC from each combined turbine and duct burner stack will be controlled by catalytic oxidation post air pollution control equipment. The use of clean, low-ash fuels and efficient combustion will limit the emissions of particulate matter in its various diameters from each combined turbine and duct burner stack.

Emissions of NOx from the auxiliary boiler will be limited through the use of a low NOx burner and an operational limit of 2,500 hours per year. Emissions of CO and VOC from the auxiliary boiler will be limited through good combustion design. The use of clean, low-ash fuels and efficient combustion will limit the emissions of particulate matter in its various diameters from the auxiliary boiler.

Emissions of NOx from the fuel gas heater will be limited through the use of a low NOx burner. Emissions of CO and VOC from the fuel gas heater will additionally be limited through good combustion design. The use of clean, low-ash fuels and efficient combustion will limit the emissions of particulate matter in its various diameters from the fuel gas heater.

Potential emissions of sulfur dioxide and sulfuric acid mist (SAM) from this project will remain below the PSD threshold (40 tpy and 7 tpy, respectively) by restricting fuel use to natural gas and ultra low sulfur diesel fuel and by limiting fuel oil combustion in each combustion turbine to no more than 1,000 hours per year (including periods of startup and shutdown).

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

3.0 REVIEW OF APPLICABLE RULES AND REGULATIONS

State Rules

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

Georgia Rule 391-3-1-.02(2)(b)Visible Emissions, limits the opacity of visible emissions from any air contaminant source, which is subject to some other emission limitation under 391-3-1-.02(2). The opacity of visible emissions from regulated sources may not exceed 40 percent under this general visible emission standard. The new combustion turbines CTG3 and CTG4 are subject to an emission standard in Rule 391-3-1-.02(2) and are therefore subject to the opacity standard specified by Georgia Rule 391-3-1-.02(2)(b). It is anticipated that the opacity of emissions from the proposed combustion turbines will be well below 40% at all times.

Georgia Rule 391-3-1-.02(2)(d) Fuel-burning Equipment limits emission of fly ash and/or particulate matter as well as opacity. Georgia Rule (d) is an applicable requirement for the new auxiliary boiler (AB2) and fuel gas preheater (FP2) because said units meet the definition of "fuel burning equipment" found in Georgia Rule 391-3-1-.01(cc). The duct burners will be direct-fired units and Georgia Rule (d) will not apply to these units. The following table provides a correlation between proposed equipment and Georgia Rule (d) applicability:

Source Code	Max Heat Input (MMBtu/hr)	Description of Equipment	Applicable Portion of Georgia Rule (d)	Maximum Allowable Emission Rate
FP2	8.75	Fuel heater	391-3-1-.02(2)(d)2.(i)	PM≤ 0.5 lb/MMBtu
AB2	17.0	Auxiliary Boiler	391-3-1-.02(2)(d)2.(ii)	PM ≤0.38 lb/MMBtu
FP2 AB2	NA	Fuel heater Auxiliary Boiler	391-3-1-.02(2)(d)3.	20% except for one six-minute period of 27%

Note 1: Georgia Rule (d) regulates particulate matter as defined by Georgia Rules 391-3-1-.01(xx) and 391-3-1-.01(yy). Particulate matter is PM and not PM10 or PM2.5. The PM emission standard for Georgia Rule (d) includes filterable plus condensable.

Georgia Rule 391-3-1-.02(2)(g), Sulfur Dioxide, applies to all "fuel-burning" sources. The following table provides a correlation between applicable equipment and Georgia Rule (g) requirements.

Source Code	Description of Equipment	Applicable Portion of Georgia Rule (d)	Maximum Allowable Emissions
FP2 (8.75 MMBtu/hr)	Fuel heater	391-3-1-.02(2)(g)2.	2.5 weight percent sulfur
AB2 (17 MMBtu/hr)	Auxiliary Boiler	391-3-1-.02(2)(g)2.	2.5 weight percent sulfur

Source Code	Description of Equipment	Applicable Portion of Georgia Rule (d)	Maximum Allowable Emissions
CTG3 >1,000 MMBtu/hr	Combustion Turbine	391-3-1-.02(2)(g)1. 391-3-1-.02(2)(g)2.	While combusting fuel oil: 0.8 lb SO_2/MMBtu 3.0 weight percent sulfur
CTG4 >1,000 MMBtu/hr	Combustion Turbine	391-3-1-.02(2)(g)1. 391-3-1-.02(2)(g)2.	While combusting fuel oil: 0.8 lb SO_2/MMBtu 3.0 weight percent sulfur
DB3 470 MMBtu/hr	Duct Burner	391-3-1-.02(2)(g)2.	3.0 weight percent sulfur
DB4 470 MMBtu/hr	Duct Burner	391-3-1-.02(2)(g)2.	3.0 weight percent sulfur

Conclusion – State Rules: The following table specifies the applicable state emission standards for the proposed project:

Emission Unit ID	Equipment	Maximum Allowable Emissions	Emission Standard Legal Authority
AB2	Auxiliary Boiler Fired on NG	PM $\leq$0.38 lb/MMBtu 20% except for one six-minute period of 27% 2.5 weight percent sulfur	391-3-1-.02(2)(d)2.(ii) 391-3-1-.02(2)(d)3. 391-3-1-.02(2)(g)2.
FP2	Fuel Heater Fired on NG	PM$\leq$ 0.5 lb/MMBtu 20% except for one six-minute period of 27% 2.5 weight percent sulfur	391-3-1-.02(2)(d)2.(i) 391-3-1-.02(2)(d)3. 391-3-1-.02(2)(g)2.
CTG3	Combustion Turbine capable of accommodating NG and FO	0.8 lb SO_2/MMBtu while firing fuel oil 3.0 weight percent sulfur 40% opacity	391-3-1-.02(2)(g)1. 391-3-1-.02(2)(g)2. 391-3-1-.02(2)(b).
CTG4	Combustion Turbine capable of accommodating NG and FO	0.8 lb SO_2/MMBtu while firing fuel oil 3.0 weight percent sulfur 40% opacity	391-3-1-.02(2)(g)1. 391-3-1-.02(2)(g)2. 391-3-1-.02(2)(b).

Emission Unit ID	Equipment	Maximum Allowable Emissions	Emission Standard Legal Authority
DB3	Duct Burner Fired on NG	3.0 weight percent sulfur 40% opacity	391-3-1-.02(2)(g)2. 391-3-1-.02(2)(b)
DB4	Duct Burner Fired on NG	3.0 weight percent sulfur 40% opacity	391-3-1-.02(2)(g)2. 391-3-1-.02(2)(b)
Cooling Towers		NA	No applicable state rule
Fuel Oil Storage Tank		NA	No applicable state rule

Federal Rules

Prevention of Significant Deterioration (40 CFR 52.21)

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

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

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

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

Definition of BACT

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

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

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

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

New Source Performance Standards

40 CFR 60 Subpart A (General Provisions) imposes generally applicable requirements for initial notifications, initial compliance testing, monitoring, and record keeping requirements.

40 CFR 60 Subpart Da (Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978)
Applicability: The regulation is applicable to each electric utility steam generating unit that is capable of combusting more than 73 megawatts (MW) (250 million British thermal units per hour) heat input of fossil fuel (either alone or in combination with any other fuel), was constructed, modified, or reconstructed after September 18, 1978[40 CFR 60.40Da(a)]. The duct burners DB3 and DB4 could potentially be subject to this regulation. However, heat recovery steam generators used with duct burners and associated with an electric utility combined cycle gas turbine that are capable of combusting more than 73 MW (250 million Btu/hr) heat input of fossil fuel are subject to this subpart except in cases when the heat recovery steam generator meets the applicability requirements and is subject to 40 CFR 60, Subpart KKKK [40 CFR 60.40Da(e)(1)]. The proposed heat recovery steam generators (HRSGs) equipped with duct burners DB3 and DB4 meet the applicability requirements of 40 CFR 60, Subpart KKKK, as discussed later in this narrative.

<u>The Division concurs with the applicant's findings that 40 CFR 60 Subpart Da is not an applicable requirement for this project.</u>

40 CFR 60 Subpart Dc (Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units):
Applicability – Auxiliary Boiler: This regulation is applicable to the proposed auxiliary boiler because this boiler has a rated heat input capacity of 17 MMBtu/hr. This auxiliary boiler will only fire natural gas. NSPS Dc does not specify any emission standards for this boiler because of its rated capacity.

Applicability – Fuel Gas Preheater: The Division concurs with the applicant's findings that the fuel pre-heater is not subject to this regulation since is input capacity is less than 10 million British Thermal Units per hour.

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): The proposed modification includes a 2.35 million gallon No. 2 fuel oil storage tank. This storage tank meets the NSPS Kb exemption specified by 40 CFR 60.110b(b) and so this NSPS is not an applicable requirement. The Division concurs with the applicant's finding.

40 CFR 60 Subpart KKKK (Standards of Performance for Stationary Combustion Turbines):
Applicability: NSPS Subpart KKKK is an applicable requirement for the combustion turbines because they each have a heat input at peak load equal to or greater than 10 MMBtu/hr, based on the higher heating value of the fuel, and both will be constructed after February 18, 2005. This subpart also applies to emissions from any associated HRSG and duct burners. Stationary combustion turbines regulated under this subpart are exempt from the requirements of Subpart GG of this part. Heat recovery steam generators and duct burners regulated under this subpart are exempted from the requirements of Part 60 Subparts Da, Db, and Dc of this part.

Emission Standard:

Pollutant	Standard	Standard Regulatory Citation	Compliance Determination Method and Citation
SO_2 from Combustion Turbines Or Total Potential Sulfur Emissions from Combustion Turbines	0.90 lb SO_2/MW-hr Or 0.060 lb SO_2/MMBtu	40 CFR 60.4330(a)(1) Or 40 CFR 60.4330(a)(2)	Testing – 60.4415 Conduct an initial performance test per 60.8 and an annual performance test. There are three methodologies that applicant may use to conduct the performance tests per 60.4415. Monitoring – 60.4365, 60.4370 Applicant may elect not to monitor the total sulfur content of the fuel combusted in the turbine if the fuel is demonstrated not to exceed 60.4330(a)(2). Demonstration may be made following one of the following methods: (a) The fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel specifying that the maximum total sulfur content for oil is 500 ppmw or less and 20 grains per 100 scf or less for natural gas and has potential sulfur emissions of less than 0.060 lb/MMBtu. Or (b) Representative fuel sampling data which show that the sulfur content of the fuel does not exceed 0.060 lb /MMBtu. At a minimum, the amount of fuel sampling data specified in Part 75 Appendix D section 2.3.1.4 or 2.3.2.4.

Pollutant	Standard	Standard Regulatory Citation	Compliance Determination Method and Citation
NOx When total heat input is greater than or equal to 50% of natural gas When total heat input is greater than or equal to 50% of fuel oil	 15 ppm @15% oxygen or 0.43 lb/MW-hr 42 ppm @15% oxygen or 1.3 lb/MW-hr	For CT heat input at peak load > 850 MMBtu/hr 40 CFR 60.4320 – Table 1 40 CFR 60.4320 – Table 1	Combined turbine and duct burner exhaust will be equipped with a NOx CEMS in accordance with Part 75 and Parts 60.4335 and 60.4345. An excess emission is any unit operating period in which the 4-hour **or** 30-day rolling average NOx emission rate exceeds the applicable limit in 60.4320.

National Emissions Standards for Hazardous Air Pollutants

40 CFR 63 Subpart YYYY (National Emissions Standards for Hazardous Air Pollutants for Stationary Combustion Turbines)*:*
Applicability: NESHAP Subpart YYYY applies to stationary combustion turbines located at major sources of HAP emissions. The new power block is to be constructed at the existing Effingham County Power plant. The existing Effingham County Power Plant is a minor source of hazardous air pollutants. The expansion of the plant will not change the minor source classification for this facility. The findings of Georgia EPD are that this NESHAP does not apply to the combustion turbines because they are to be located at an area source of HAPs.

40 CFR 63 Subpart DDDDD (National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters)
Applicability: On February 21, 2011, EPA finalized a rule addressing HAPs emitted from existing and new institutional, commercial, and institutional boilers located at a major source of HAPs. The existing Effingham County Power Plant is a minor source of HAPs. Addition of the power block with requested operational restrictions will aid the entire facility in remaining a minor source of HAPs. NESHAP DDDDD is not an applicable requirement for this project. The Division concurs with this finding.

40 CFR 63 Subpart JJJJJJ (National Emission Standards for Area Sources: Industrial/Commercial/Institutional Boilers)
Applicability: On February 21, 2011, EPA finalized a rule addressing HAPs emitted from existing and new institutional, commercial, and institutional boilers located at an areas source. The fuel heater (Source Code: FP2) and auxiliary boiler (Source Code AB2) are not subject to this regulation because they will be permitted to only fire natural gas (i.e., 40 CFR 63.11195).

40 CFR 64, Compliance Assurance Monitoring [CAM]: Except for backup utility units that are exempt under paragraph (b)(2) of 40 CFR 64.2, the requirements of 40 CFR 64 apply to a pollutant-specific emissions unit at a major source that is required to obtain a part 70 or 71 permit if the unit satisfies all of the following criteria: (1) The unit is subject to an emission limitation or standard for the applicable regulated air pollutant (or a surrogate thereof), other than an emission limitation or standard that is exempt under paragraph (b)(1) of 40 CFR 64.2; (2) The unit uses a control device to achieve compliance with any such emission limitation or standard; and (3) The unit has potential pre-control device emissions of the applicable regulated air pollutant that are equal to or greater than 100 percent of the amount, in tons per year, required for a source to be classified as a major source. Where "potential pre-control device emissions" has the same meaning as "potential to emit," as defined in

§64.1, except that emission reductions achieved by the applicable control device are not taken into account [40 CFR 64.2(a)].

Applicability for NOx Emissions from CT/HRSG combined stack: Emissions of NOx from the combustion turbine/heat recovery steam generator (CT/HRSG) combined stack are proposed to be controlled by selective catalytic reduction. Emissions of NOx from the CT portion of the CT/HRSG train are controlled by dry low NOx combustors for natural gas combustion and water injection for fuel oil combustion.

NSPS KKKK NOx Emission Limit: The NSPS KKKK NOx emission limit from the combustion turbine/heat recovery steam generator (CT/HRSG) are excluded from CAM applicability for the following reason:

- The CT/HRSG combined stack NOx emissions are subject to the requirements of 40 CFR Subpart KKKK. This NSPS was promulgated after November 15, 1990 and therefore the CT/HRSG system is exempt from the requirements of CAM.

NOx BACT Emission Limit: CO emissions from each new combustion turbine/duct burner combined stack (emission unit ID Nos. CTG3/DB3 and CTG4/DB4) are subject to CAM applicability because the continuous compliance determination method is the applicable reference test method. The applicant did not submit a CAM plan application; however, the Division has included Part 64 requirements for CO emissions in the draft permit.

Applicability for CO Emissions from CT/HRSG combined stack: Emissions of CO from the CT/HRSG combined stack are proposed to be controlled by catalytic oxidation. CO emissions from the CT/HRSG will be tracked via a CO continuous emissions monitoring system; however, the facility requested that the reference test method be the official compliance determination method (via telephone call with Susan Jenkins on February 3, 2012). CO emissions from each new combustion turbine/duct burner combined stack (emission unit ID Nos. CTG3/DB3 and CTG4/DB4) are subject to CAM applicability because the continuous compliance determination method is the applicable reference test method. The applicant did not submit a CAM plan application; however, the Division has included Part 64 requirements for CO emissions in the draft permit.

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

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

Regulated toxic and flammable substances under section 112(r) of the Clean Air Act are the substances listed in Tables 1, 2, 3, and 4. Threshold quantities for listed toxic and flammable substances are specified in the tables [40 CFR 68.130(a)]. Page 25 of the application indicates that Effingham has committed to using an ammonia mixture with an ammonia solution less than the 20 percent, the regulated concentration for aqueous ammonia. Under Table 1 thresholds, ammonia solutions less than 20% are not regulated. Effingham has not yet purchased the ammonia storage tank but has committed to using a maximum 19% ammonia solution. Therefore, ammonia storage at the Effingham facility is not subject to reporting under this regulation.

Acid Rain Program

The proposed project is subject to the provisions of the Federal Acid Rain program because the proposed project has a generating capacity greater than 25 MW. The proposed project is classified under 40 CFR Part 73 as a Phase II project and the facility has submitted a Phase II Acid Rain Permit Application which will be incorporated into their PSD/Title V permit.

Clean Air Interstate Rule (CAIR)

40 CFR 96 Subparts AA through HH and Subparts AAA through HHH*:* The federal Clean Air Interstate Rule requirement will not apply to the proposed project because of the promulgation of the Cross-State Air Pollution Rule in July 2011.

Note: As of December 30, 2011 the Clean Air Interstate Rule will apply because the Cross State Air Pollution Rule was stayed by the federal court on December 30, 2011.

Cross-State Air Pollution Rule (Transport Rule)

The Cross-State Air Pollution Rule (CSAPR) was promulgated on August 8, 2011. The new power block will be regulated as a "new unit" under CSAPR as discussed in the following regulatory provisions (1) Annual NOx per 40 CFR Part 97.411(b) and Part 97.412; (2) Ozone Season NOx per 40 CFR Part 97.511(b) and Part 97.512; and (3) Annual SO_2 Group 2 in 40 CFR Part 97.711(b) and Part 97.712. The new power block will become subject to CSAPR on the first date on which it both combusts fossil fuel and serves a generator greater than 25 MW. Allocations under CSAPR will be permitted at a later date. This federal rule was stayed by the federal court on December 30, 2011.

Greenhouse Gas (GHG) Reporting Program (40 CFR 98)

In response to the FY2008 Consolidated Appropriations Act (H.R. 2764; Public Law 110-161), EPA issued the Mandatory Reporting of Greenhouse Gases Rule (74 FR 5620) which requires reporting of greenhouse gas (GHG) data and other relevant information from large sources and suppliers in the United States. The purpose of this rule is to collect accurate and timely GHG data to inform future policy decisions. In general, the Rule is referred to as 40 CFR Part 98. Implementation of Part 98 is referred to as the Greenhouse Gas Reporting Program (GHGRP). The GHGRP is not an applicable requirement for the applicant's PSD/Title V amendment and is therefore not included.

Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule

On June 3, 2010 (75 FR 31514-31608), the U.S. EPA issued a final rule that establishes an approach to addressing greenhouse gas emissions from stationary sources under the Clean Air Act (CAA) permitting programs. This final rule sets thresholds for GHG emissions that define when permits under the New Source Review PSD and title V Operating Permit programs are required for new and existing industrial facilities.

The CAA permitting program emissions thresholds for criteria pollutants such as lead, sulfur dioxide and nitrogen dioxide, are 100 and 250 tpy. While these thresholds are appropriate for criteria pollutants, they are not feasible for GHGs because GHGs are emitted in much higher volumes.

The final rule addresses emissions of a group of six GHGs:

1. Carbon dioxide (CO2)
2. Methane (CH4)
3. Nitrous oxide (N2O)
4. Hydrofluorocarbons (HFCs)
5. Perfluorocarbons (PFCs)
6. Sulfur hexafluoride (SF6)

Some of these GHGs have a higher global warming potential than others. To address these differences, the international standard practice is to express GHGs in carbon dioxide equivalents (CO_2e). Emissions of gases other than CO_2 are translated into CO_2e by using the gases' global warming potentials. Under this rule, EPA is using CO_2e as the metric for determining whether sources are covered under permitting programs. Total GHG emissions will be calculated by summing the CO_2e emissions of the six aforementioned constituent GHGs.

The Step 2 date of July 1, 2011 has passed and applicability is addressed as follows for this project:

- The existing plant has the potential to emit greater than 100,000 tpy CO_{2e} emissions;
- The project has the potential to emit greater than 75,000 tpy CO_{2e} emissions;
- Therefore emissions of GHGs are classified as a "regulated NSR Pollutant"; and
- Potential emissions of GHGs (as CO_{2e}) are greater than 0 tpy and are therefore subject to PSD requirements for BACT.

State and Federal – Startup and Shutdown and Excess Emissions

Startup and shutdown of the combined-cycle systems are part of *normal source operation* and the regulatory requirements of 40 CFR 52.21(j) apply during all periods of *normal source operation*. The applicant is requesting authorization to operate the new power block at 50% to 100% of the maximum load adjusted for ambient conditions. The following table specifies the startup and shutdown scenario described by the applicant: Note: The applicant approved the information found in this table on November 18, 2011.

Fuel Type	Control Technology	Operational Loads	Notes
Natural Gas	None for this period of startup	~0% to 59.5% of the maximum load adjusted for ambient conditions	Operation classified as startup.
Natural Gas	Dry Low NOx Combustors (DLN) Selective Catalytic Reduction (SCR) Catalytic Oxidation	~60% to 69.9% of maximum load adjusted for ambient conditions.	This operational range is classified as startup. DLN begins at 60% of the maximum load adjusted for ambient conditions. SCR is initiated within 5 minutes of DLN initiation.

Fuel Type	Control Technology	Operational Loads	Notes
Natural Gas	DLN Combustors and SCR	~70% to 100% of maximum load adjusted for ambient conditions	Non-startup to baseload operation.
Hybrid Fuel Startup	None for this period of startup	~0% to 10.4% of maximum load adjusted for ambient conditions	Operation is classified as startup. Applicant may only fire natural gas.
Hybrid Fuel Startup	SCR is initiated at ~10.4% of maximum load adjusted for ambient conditions Catalytic Oxidation	~10.4% to 49.9% of maximum load adjusted for ambient conditions	Operation classified as startup. Applicant may fire fuel oil.
Hybrid Fuel Startup	Water Injection Operation of SCR Operation of Catalytic Oxidation	~50% to 69.9% of maximum load adjusted for ambient conditions	Operation is classified as startup. Applicant may fire fuel oil.
Hybrid Fuel Startup	Water Injection Operation of SCR Operation of Catalytic Oxidation	~70% to 100% of maximum load adjusted for ambient conditions.	Non-startup to baseload operation.
Applicant requests an operational restriction limiting startup plus shutdown hours to 1,099 hours during any twelve consecutive months for each new combustion turbine (CTG3 and CTG4). The applicant is limited to 1,000 hours per year on fuel oil per new combustion turbine (CTG3 and CTG4) including periods of startup and shutdown.			

4.0 CONTROL TECHNOLOGY REVIEW

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

4.1 Combustion Turbine/Duct Burner

<u>Oxides of Nitrogen</u>

Top-Down BACT Alternatives: The applicant identified and performed detailed discussion of the following NOx control technology for natural gas and/or fuel oil combustion in each combustion turbine:

- Water injection
- Dry low NOx combustors

- Selective Catalytic Reduction (SCR)
- SCONOx Process
- XONON™ Catalytic Combustor
- NOxOUT Process
- Thermal DeNOx
- Selective Non-Catalytic Reduction (SNCR)
- Non-Selective Catalytic Reduction (NSCR)

Please refer to Chapter 4.3.1 of Application No. 19810 for details on the NOx control technologies. Georgia EPD supports the applicant's findings.

Technical Feasibility Analysis: The following table summarizes Application No. 19810 discussion on eliminating technically infeasible options. For a detailed discussion, please see pages 36 through 38 of Application No. 19810. The Division concurs with the facility's findings.

Control Technology	Considered Technically Feasible	Reason for Decision
Water Injection	Yes	Demonstrated Technology for a large combined cycle gas turbine unit.
DLN Combustors	Yes	Demonstrated Technology for a large combined cycle gas turbine unit.
SCR	Yes	Demonstrated Technology for a large combined cycle gas turbine unit.
NO_xOUT	No	Not yet been commercially operated on any large combined cycle gas turbine unit.
Thermal $DeNO_x$	No	No known applications to combined cycle units
SNCR	No	Exhaust temperature of the turbines will not approach the operating temperature window for SNCR.
NSCR	No	Oxygen levels in exhaust streams for the combustion turbines are too high for effective operation of NSCR.
$SCONO_x$	No	Not yet been commercially operated on any large combined cycle gas turbine unit.
XONON	No	Not yet been commercially operated on any large combined cycle gas turbine unit.

Ranking the Technically Feasible Alternatives: The applicant did not rank the technically feasible control technology by control effectiveness. 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 Division reviewed the applicant's analysis of the most effective controls and the Division agrees with the applicant's energy, environmental and economic impact analyses.. Please refer to Section 4.3.1.5 of the July 2010 application for the applicant's step 4 analysis.

The applicant proposed the following NOx BACT for the combined CT/HRSG stack on page 39 of the application. Effingham provided the results of their review of the RACT/BACT/LAER Clearinghouse (RBLC) database and their findings are included in Tables 4-1 and 4-2 of the applicant's July 2010 application. The applicant did not propose BACT for all periods of startup and shutdown (SUSD).

The following tables include the baseline state and/or federal NOx emission standards for comparison.

Applicant's NOx BACT Selection for Natural Gas Combustion in CTs and DBs

Control Option	**State and/or Federal Legal Authority**	**NOx BACT Proposal**
DLN + SCR	Part 52.21(j)	2.5 ppmvd @ 15% oxygen, 24-hour averaging period, does not apply during periods of startup and shutdown (SUSD) Limit annual hours of operation per DB to 4,000.
Baseline for CT plus HRSG equipped with DB	NSPS KKKK (40 CFR 60.43.20 – Table 1) When total heat input is greater than or equal to 50% of natural gas	15 ppm @ 15% oxygen on a 30-day rolling average or 0.43 lb NOx/MW-hr

Applicant's NOx BACT Selection for Fuel Oil Combustion in CTs

Control Option	**State and/or Federal Legal Authority**	**NOx BACT Proposal**
Water Injection + SCR	40 CFR 52.21(j)	10 ppmvd @ 15% oxygen, 24-hour averaging period, does not apply during periods of SUSD. Firing of fuel oil limited to 1,000 hours during any twelve consecutive months per CT.
Baseline for CT plus HRSG equipped with DB Note that DB will only be fired with natural gas.	NSPS KKKK (40 CFR 60.43.20 – Table 1) –When total heat input is greater than or equal to 50% of fuel oil	42 ppm @ 15% on a 30-day rolling average or 1.3 lb/MW-hr

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

- USEPA RACT/BACT/LAER Clearinghouse[1]: The Division conducted its own standard review (ten year look back) of the RBLC and the results of the Division's findings are specified in **Appendix D** of this document.
- National Combustion Turbines List (October 5, 2010)[2]
- Final Permit, Preliminary Determination, and Final Determination for Live Oaks Power Plant Air Permit Number 4911-127-0075-P-02-0[3]
- Final Permit, Preliminary Determination, and Final Determination McIntosh Combined Cycle Facility Air Permit Number 4911-103-0014-V-01-0[4]
- Final Permit and Statement of Basis, AECI – Dell Power Plant Air Permit Number 1903-AOP-R7 March 31, 2010
- California Environmental Protection Agency Air Resources Board Website[5]
- GE New 7FA Specifications[6]
- *Report to the Legislature Gas-Fired Power Plant NO_x Emission Controls and Related Environmental Impacts*, California Environmental Protection Agency Air Resources Board Stationary Source Division, May 2004

Natural Gas Combustion in CT plus DB: The Division has determined that the proposal to use DLN combustor/burner technology in conjunction with SCR post-combustion air pollution control meets the requirement for BACT for natural gas combustion. The Division proposes the following BACT emission limits:

Pollutant	BACT	Compliance Demonstration
NOx	2.0 ppmvd @ 15% oxygen on a 3-hour average, excluding periods of SUSD Note: This concentration is equivalent to 28.8 lb/hr	NOx CEMS per Part 75 Reference Test Method 7E-Compliance determination method
NOx	Each duct burner is limited to 4,000 hours per year of operation	Hours meter
NOx	Limit hours of operation associated with SUSD to 1,099 per CT/HRSG system with SUSD defined	Hours meter

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

[2] http://www.epa.gov/region4/air/permits/national_ct_list.xls

[3] http://www.georgiaair.org/airpermit/downloads/permits/12700075/psd18569/1270075final.pdf

[4] http://www.georgiaair.org/airpermit/downloads/permits/10300003/psd13404/1030014fp.pdf

[5] http://www.arb.ca.gov/homepage.htm

[6] http://www/ge-7fa.com/businesses/ge-7fa/en/7FA-tech-spects.html

Pollutant	BACT	Compliance Demonstration
NOx	210 tpy, including SUSD, for each CT/HRSG	NOx CEMS

As noted earlier, the applicant did not propose a NOx BACT emission limit that included periods of SUSD for each CT/HRSG system. Therefore, the Division derived an annual NOx BACT emission limit for each CT/HRSG system of 210 tpy, which includes periods of SUSD, and which is computed as follows:

NOx (tpy) = [(183.1 lb NOx SUSD/hr)*(1,099 hrs SUSD/yr) + (28.8 lb NOx at 60% to 100% of load)*(7,661 hrs/yr)]*(1 ton/2000 lb)

NOx (tpy) = 210 tpy.

where SUSD = startup and shutdown.

Fuel Oil Combustion in CT: The Division has determined that the proposal to use water injection in conjunction with SCR post-combustion air pollution control meets the requirement for BACT for fuel oil combustion.

The McIntosh Combined-Cycle Facility (AIRS #: 103-00014) tested for NOx emissions from fuel oil firing in a GE 7FA combustion turbine in March of 2005. The 3-hour average NOx emission rate (from three 1-hour tests) was approximately 5.866 ppm (full load) and 5.106 ppm (partial load) @ 15% oxygen at full load while the BACT limit was 6.0 ppmvd @ 15% oxygen on a 3-hour average. The applicant reiterated in writing to the Division:

- In a letter dated August 3, 2011 that the NOx BACT limit during fuel oil firing should be no lower than 10 ppmvd @ 15% oxygen; and
- In a letter dated January 30, 2012 that an SCR control efficiency of approximately 86% would be required to achieve a 6 ppmvd@ 15% oxygen NOx limit during fuel oil combustion and that this SCR control efficiency over all periods of non-startup and shutdown would be difficult to achieve.

The modeled NOx emission rate was 183.1 lb/hr (equivalent to a NOx concentration of approximately 26.6 ppmvd @15% oxygen (with a heating value of 1,768.9 MMBtu/hr).

The Division accepts the applicant's BACT proposal based on the NOx test data from fuel oil combustion at the McIntosh Combined-Cycle Facility. The Division proposes the following BACT emission limits.:

Pollutant	BACT	Compliance Demonstration
NOx	10.0 ppmvd @ 15% oxygen on a 3-hour average, excluding periods of SUSD Note: This concentration is equivalent to 68.8 lb/hr	NOx CEMS Reference Test Method 7E – Compliance determination method
NOx	Operation on fuel oil in each combustion turbine is limited to 1,000 hours per year	Hours meter

Pollutant	BACT	Compliance Demonstration
NOx	Limit hours of operation associated with SUSD to 1,099 per CT/HRSG system with SUSD defined	Hours meter
NOx	67 tpy, including SUSD, for each CT/HRSG	NOx CEMS

The applicant did not propose a NOx BACT emission limit for startup and shutdown or one that would include startup and shutdown. Therefore, the Division derived an annual NOx BACT emission limit, including periods of SUSD, of 67 tpy which is computed as follows:

NOx (tpy) = [135.4 lb NOx SUSD/hr)*(1,000 hrs/yr)]*(1 ton/2000 lb)
NOx (tpy) = 67 tpy

Carbon Monoxide and Volatile Organic Compounds

Top-Down BACT Alternatives for Carbon Monoxide and Volatile Organic Compounds: The applicant identified and performed detailed discussion of the following CO and VOC control technology for natural gas or fuel oil combustion in each combustion turbine. Georgia EPD supports the applicant's findings.

- Combustion controls
- Oxidation catalyst
- SCONOx Process

Please refer to Chapter 4.3.2 of Application No. 19810 (July 2010) for details on the CO and VOC control technologies.

Technical Feasibility Analysis: The following table summarizes Application 19810 discussion on eliminating technically infeasible options. For a detailed discussion, please see page 41 of Application 19810. Georgia EPD supports the applicant's conclusions.

Control Technology	Considered Technically Feasible	Reason for Decision
Combustion Controls	Yes	Demonstrated Technology for a large combined cycle gas turbine unit.
Oxidation Catalyst	Yes	Demonstrated Technology for a large combined cycle gas turbine unit.
$SCONO_x$	No	Not yet been commercially operated on any large combined cycle gas turbine unit.

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.

Applicant's CO and VOC BACT Emission Standard Analysis:
The applicant's evaluation of economic, environmental, and energy impacts of feasible technologies is presented in Section 4.3.2.5 of the application (July 2010). Effingham searched the

RACT/BACT/LAER Clearinghouse (RBLC) database and its findings are included in Tables 4-1 and 4-2 of Application 19810. The Division does not support the applicant's claim that the use of catalytic oxidation was not cost effective. The Division believes the applicant's proposal for use of catalytic oxidation for control of CO and VOC emissions is cost effective and is technically feasible. The applicant was notified of these findings in a letter dated January 25, 2011. Note that the applicant did not present emissions from fuel oil combustion during SUSD until July 2011.

Applicant's CO BACT Proposal while firing Natural Gas in CT and DB

Control Option	**State and/or Federal Legal Authority**	**CO BACT Proposal**	**VOC BACT Proposal**
Catalytic Oxidation Applicant deemed this option as not cost effective. ~$2,883/ton of CO and VOC removed per Table 4-8 dated March 22, 2011 **Applicant deemed not cost effective.**	40 CFR 52.21(j)	2.0 ppmvd @ 15% oxygen, 3-hour average, does not include periods of SUSD, with and without duct firing	1.0 ppmvd @ 15% oxygen, 3-hour average, does not include periods of SUSD
Baseline for CT plus HRSG equipped with DB – Proper Combustion Design and Operation **Applicant's proposal.**	40 CFR 52.21(j) Proper Combustion Design and Operation	<u>Revised Table 4-8 dated March 22, 2011</u> W/O duct firing: 3.0 ppmvd @ 15% oxygen, does not include periods of SUSD <u>Revised Table 4-8 dated March 22, 2011</u> W/ duct firing 10.0 ppmvd @ 15% oxygen, does not include periods of SUSD Limit hours of SUSD per CT/HRSG to 1,099 per year	<u>Revised Table 4-8 dated March 22, 2011</u> W/O duct firing: 1.4 ppmvd @ 15% oxygen, does not include periods of SUSD <u>Revised Table 4-8 dated March 22, 2011</u> W/duct firing: 2.0 ppmvd @ 15% oxygen, does not include periods of SUSD Limit hours of SUSD per CT/HRSG to 1,099 per year

Applicant's CO and VOC BACT Proposal while firing Fuel Oil in CT

Control Option	State and/or Federal Legal Authority	CO BACT Proposal	VOC BACT Proposal
Catalytic Oxidation Applicant deemed this option as not cost effective. ~$2,883/ton of CO and VOC removed per Table 4-8 dated March 22, 2011 **Applicant deemed not cost effective.**	40 CFR 52.21(j)	4.0 ppmvd @ 15% oxygen, 3-hour average, does not include periods of SUSD, with and without duct firing	1.75 ppmvd @ 15% oxygen, 3-hour average, does not include periods of SUSD
Baseline for CT plus HRSG equipped with DB – Proper Combustion Design and Operation **Applicant's proposal.**	40 CFR 52.21(j)	<u>Revised Table 4-8 dated March 22, 2011</u> W/O duct firing: 20.0 ppmvd @ 15% oxygen, does not include periods of SUSD Limit fuel oil firing in each CT to 1,000 hours per year	<u>Revised Table 4-8 dated March 22, 2011</u> W/O duct firing: 3.5 ppmvd @ 15% oxygen, does not include periods of SUSD Limit fuel oil firing in each CT to 1,000 hours per year.

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

- USEPA RACT/BACT/LAER Clearinghouse[7] as stated in **Appendices E and F** of this document.
- National Combustion Turbines List (October 5, 2010)[8]
- Final Permit, Preliminary Determination, and Final Determination for Live Oaks Power Plant Air Permit Number 4911-127-0075-P-02-0[9]
- Final Permit, Preliminary Determination, and Final Determination McIntosh Combined Cycle Facility Air Permit Number 4911-103-0014-V-01-0[10]
- Final Permit, PSD Engineering Analysis, Summary of Changes to the Permit Dominion – Warren County Power Station Registration Number 81391
- Final Permit, NSR Engineering Evaluation, Summary of Permit Modifications Kleen Energy Systems, LLC Town-Permit Number 104-0131
- GE New 7FA Specifications[11]
- California Environmental Protection Agency Air Resources Board Website[12]

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

[8] http://www.epa.gov/region4/air/permits/national_ct_list.xls

[9] http://www.georgiaair.org/airpermit/downloads/permits/12700075/psd18569/1270075final.pdf

[10] http://www.georgiaair.org/airpermit/downloads/permits/10300003/psd13404/1030014fp.pdf

[11] http://www/ge-7fa.com/businesses/ge-7fa/en/7FA-tech-spects.html

Natural Gas Combustion in CT and DB: The Division has determined that the proposal to use DLN combustor/burner technology in conjunction with catalytic oxidation post-combustion air pollution control meets the requirements for CO and VOC BACT for natural gas combustion.

Control Option	State and/or Federal Legal Authority	CO BACT Proposal	VOC BACT Proposal
Catalytic Oxidation	40 CFR 52.21(j)	2.0 ppmvd @ 15% oxygen, 3-hour average, does not include periods of SUSD	2.0 ppmvd @ 15% oxygen, 3-hour average, does not include periods of SUSD
NA	40 CFR 52.21(j)	Each duct burner is limited to 4,000 hours per year of operation	Each duct burner is limited to 4,000 hours per year of operation
NA	40 CFR 52.21(j)	Limit hours per year of SUSD per CT/HRSG system to 1,099.	Limit hours per year of SUSD per CT/HRSG system to 1,099
NA	40 CFR 52.21(j)	236 tpy per CT/HRSG including periods of SUSD	NA – Cannot be technically measured or monitored

The following calculations serve to estimate mass emission rates of VOC and CO including SUSD:

Assumptions	Values
CO emission rate per CT at baseload per Table 2-4 of application	12.5 lb/hr at 7,761 hrs/yr (excluding SUSD) without control
CO emission rate per DB at baseload per Table 2-4 of application	(52.0 lb/hr-12.5 lb/hr) = 39.5 lb/hr at 4,000 hrs/yr (excluding SUSD) without control
CO emission rate per hour of SUSD per Table 2-3 of application, without control	Hour 1: 234.1 lb/hr Hour 2: 208.60 lb/hr Hour 3: 164.7 lb/hr Hour 4: 660.6 lb/hr Hour 5: 177.5 lb/hr Total hours of SUSD per CT/HRSG is 1,099 per year
Oxidation catalyst control efficiency during SUSD per July 1, 2011 application addendum	Hour 1: 40% control Hour 2: 80% control Hour 3: 80% control Hour 4: 80% control Hour 5: 80% control

For CT/HRSG: CO (tpy) = (1 ton/2000 lb)*[(12.5 lb/hr)*(7761 hrs/yr) + (39.5 lb/hr)*(4,000 hrs/yr)]*(0.20)

For CT/HRSG: CO (tpy) = 25.50 tpy

For SUSD: CO (tpy) = (1 ton/2000 lb)*(1,099 hrs/yr)*[(234.1 lb/hr)*(0.60) + (208.60 lb/hr)*(0.20) + (164.7 lb/hr)*(0.20) + (660.6 lb/hr)*(0.20) + (177.5 lb/hr)*(0.20)]

For SUSD: CO (tpy) = (1 ton/2000lb)*(1,099 hrs/yr)[140.60 lb/hr+41.72 lb/hr + 32.94 lb/hr + 132.1 lb/hr + 35.5 lb/hr]

For SUSD: CO (tpy) = (1 ton/2000 lb)*(1,099 hrs/yr) [382.86 lb/hr]

[12] http://www.arb.ca.gov/homepage.htm

For SUSD: CO (tpy) = 210.38 tpy

Total CO [CT/HRSG plus SUSD] = 25.50 tpy + 210.38 tpy = 235.88 tpy

Fuel Oil Combustion in CT: The Division has determined that the proposal to use water injection in conjunction with catalytic oxidation post-combustion air pollution control meets the requirements for CO and VOC BACT for fuel oil combustion.

The McIntosh Combined-Cycle Facility (AIRS #: 103-00014) tested for CO and VOC emissions from fuel oil firing in a GE 7FA combustion turbine in March of 2005. The McIntosh Combined-Cycle Facility also operates a catalytic oxidation unit for the control of CO and VOC emissions from the GE 7FA combustion turbines. The 3-hour average CO emission rate (from three 1-hour tests) is specified in the following table:

Unit ID	CO ppm @15% oxygen	VOC ppm @ 15% oxygen	BACT Limits ppmvd @ 15% oxygen
11A	0.157 – partial load 0.046 – full load	0.015 – partial load	CO: 2.0 VOC: 2.0
11B	0.127 – partial load 0.090 – full load	0.087 – partial load	CO: 2.0 VOC: 2.0

The applicant reiterated in writing to the Division:

- In a letter dated January 30, 2012 that the CO BACT limit during fuel oil firing should be no lower than 4.0 ppmvd @ 15% oxygen with the use of a catalytic oxidation unit; and
- In a letter dated January 30, 2012 that the VOC BACT limit during fuel oil firing should be no lower than 2.3 ppmvd @ 15% oxygen with the use of a catalytic oxidation unit. In addition the applicant requested that the BACT limit not reference an averaging period.

Based on the results of testing at Plant McIntosh, the Division proposes the following CO and VOC BACT limits during fuel oil combustion. The draft permit will include the averaging period in order to specify BACT for the applicable pollutants and the compliance determination method will be the reference test method.

Control Option	State and/or Federal Legal Authority	CO BACT Proposal	VOC BACT Proposal
Catalytic Oxidation	40 CFR 52.21(j)	2.0 ppmvd @ 15% oxygen, 3-hour average, does not include periods of SUSD	2.0 ppmvd @ 15% oxygen, 3-hour average, does not include periods of SUSD
NA	40 CFR 52.21(j)	Limit fuel oil combustion to 1,000 hours per year per CT. This limit also limits hours of SUSD from 1,099 to 1,000 hours per year per CT.	Limit fuel oil combustion to 1,000 hours per year per CT. This limit also limits hours of SUSD from 1,099 to 1,000 hours per year per CT.
NA	40 CFR 52.21(j)	46.4 tpy per CT/HRSG system including SUSD	NA, Cannot be technically measured

Assumptions	Values
CO emission rate per CT at baseload per Table 2-4 of application	92.8 lb/hr for 1,000 hrs/yr, excluding SUSD, without control/
CO emission rate per hour of SUSD per July 1, 2011 application addendum, after control	Hour 1: 114.0 lb/hr Hour 2: 30.0 lb/hr Hour 3: 30.4 lb/hr Hour 4: 37.4 lb/hr Hour 5: 12.7 lb/hr Avg = 44.9 lb/hr Total hours of SUSD per CT/HRSG is 1,000 per year

For CT/HRSG: CO (tpy) = (1 ton/2000 lb)*[(92.8 lb/hr*(1,000 hrs/yr)]
For CT/HRSG: CO (tpy) = 46.4 tpy

For SUSD: CO (tpy) = (1 ton/2000 lb)*(1,000 hrs/yr)*(44.9 lb/hr)
For SUSD: CO (tpy) = 22.45 tpy

PM, PM_{10}, and $PM_{2.5}$ Emissions

Emissions of PM, PM_{10}, and $PM_{2.5}$ result from inert solids contained in the fuel, unburned fuel hydrocarbons which agglomerate to form particles. The regulated NSR pollutant for PM, PM10, and PM2.5 is the filterable portion plus the condensable portion of the PM, PM10, and PM2.5.

Top-Down BACT Alternatives: The applicant identified and performed detailed discussion of the following NOx control technology for natural gas or fuel oil combustion in each combustion turbine. Georgia EPD supports the applicant's findings.

- Good Combustion Practices (GCP)
- Fuels with low sulfur and low ash content
- Fabric Filter Baghouse
- Electrostatic Precipitator
- Wet Electrostatic Precipitator
- Wet Scrubber

EPD also includes the following technologies to minimize emissions of PM, PM10, and PM2.5:

- Cyclones
- Fuels with low sulfur and low ash content coupled with air inlet cooler/filter, and lube oil vent coalescer (demister)

Please refer to Chapter 4.3.3.2 of Application No. 19810 (July 2010) for details on the PM, PM10, and PM2.5 control technologies.

Technical Feasibility Analysis: The following table summarizes Application 19810 (July 2010) discussion on eliminating technically infeasible options. For a detailed discussion, please see pages 46 through 47 of Application 19810. Georgia EPD adds as a technically feasible control alternative the use of an air inlet cooler/filter and lube oil vent coalesce (demister).

Control Technology	Considered Technically Feasible	Reason for Decision

Control Technology	Considered Technically Feasible	Reason for Decision
Good Combustion Practices	Yes	Demonstrated Technology for a large combined cycle gas turbine unit.
Use of fuels with low sulfur and low ash content coupled with air inlet cooler/filter and lube oil vent coalescer (demister)	Yes	Demonstrated Technology for a large combined cycle gas turbine unit.
Fabric Filter Baghouse	No	A large combined cycle gas turbine unit has high volumes of airflow, fine particulate distribution, and inherently low uncontrolled PM emission rates.
Electrostatic Precipitator	No	A large combined cycle gas turbine unit has high volumes of airflow, fine particulate distribution, and inherently low uncontrolled PM emission rates.
Wet Electrostatic Precipitator	No	A large combined cycle gas turbine unit has high volumes of airflow, fine particulate distribution, and inherently low uncontrolled PM emission rates.
Wet Scrubber	No	A large combined cycle gas turbine unit has high volumes of airflow, fine particulate distribution, and inherently low uncontrolled PM emission rates.
Cyclone	No	A large combined cycle gas turbine unit has high volumes of airflow, fine particulate distribution, and inherently low uncontrolled PM emission rates.

Ranking the Technically Feasible Alternatives: The applicant discussed the technically feasible control alternatives in Chapter 4.3.3.4 of their application (July 2010). Georgia EPD adds as a technically feasible control alternative the use of low ash fuel coupled with air inlet cooler/filter and lube oil vent coalesce (demister).

The BACT Emission Standard Analysis: The applicant presented an evaluation of economic, environmental, and energy impacts of feasible technologies in Chapter 4.3.3.5 of the application (July 2010). The Division concurs with the applicant's findings.

Applicant's PM, PM10, and PM2.5 BACT Selection: There are no applicable state or federal rules which specify the allowable PM, PM10, or PM2.5 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, PM10, or PM2.5 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 470 MMBtu/hr, the maximum allowable particulate matter emission rate per duct burner under Georgia Rule (d) is 0.10 lb/MMBtu. Effingham searched the RACT/BACT/LAER Clearinghouse (RBLC) database and their findings are included in Tables 4-1 and 4-2 of Application 19810.

Applicant's BACT Selection for Natural Gas Combustion in CTs and DBs

Control Option	**State and/or Federal Legal Authority**	**PM, PM10, and PM2.5 BACT Proposal**
Use of Good Combustion Design and Operation. Use of pipeline quality natural gas with a sulfur content limit of 0.5 grains per 100 standard cubic feet.	Part 52.21(j)	Application page 47 W/O duct firing: 0.0084 lb/MMBtu, does not include periods of SUSD This limit corresponds to 50% load and 95 deg F. Application page 43 W/ duct firing: 0.0062 lb/MMBtu, does not include periods of SUSD This limit corresponds to baseload at 95 deg F. Limit operation of each DB to 4,000 hours per year. Limit hours of SUSD for each CT/HRSG system to 1,099 hours per year. **Updated Proposal 8/3/2011** **Use of pipeline quality natural gas with a sulfur content not to exceed 0.5 grains per 100 standard cubic feet as found in Permit No. 4911-127-0075-P-02-0 (Live Oaks Power Plant Permit) issued 4/8/2010.**

Applicant's BACT Selection for Fuel Oil Combustion in CTs (duct firing on NG)

Control Option	**State and/or Federal Legal Authority**	**PM, PM10, and PM2.5 BACT Proposal**
Use of Good Combustion Design and Operation. Use of ULSD at 15 ppm, low ash	Part 52.21(j)	Application page 47 W/O duct firing: 0.0153 lb/MMBtu, does not include periods of SUSD This limit corresponds to 50% load and 95 deg F. Application page 43 W/ duct firing

Control Option	State and/or Federal Legal Authority	PM, PM10, and PM2.5 BACT Proposal
		0.0103 lb/MMBtu, does not include periods of SUSD This limit corresponds to baseload at 95 deg F.

EPA noted in their comments to Georgia EPD, in a letter dated June 7, 2011, a number of facilities with similar natural gas-fired CTs in Region 4 have a PM limit of 0.0054 lb/MMBtu (*e.g.,* Live Oaks power Project, GA). This value is lower than the PM limit proposed by the applicant for natural gas firing of 0.0084 lb/MMBtu. EPA continued in their comment that based on review of the information available, the lower PM limits are technically feasible and should be considered as an option in the BACT analysis.

EPD PM, PM10, and PM2.5 BACT Selection: In addition to reviewing the permit application and supporting documentation, the Division has performed independent research of the PM, PM_{10}, $PM_{2.5}$ BACT analysis and used the following resources and information:

- USEPA RACT/BACT/LAER Clearinghouse[13] - The Division conducted its own standard review (ten year look back) of the RBLC and the results of the Division findings for particulate matter of any size is found in **Appendix G** of this document. Note that particulate matter emission rates found in the RBLC may only represent the filterable portion of particulate matter.
- National Combustion Turbines List (October 5, 2010)[14]
- Final Permit, Preliminary Determination, and Final Determination for Live Oaks Power Plant Air Permit Number 4911-127-0075-P-02-0[15]
- Final Permit, Preliminary Determination, and Final Determination McIntosh Combined Cycle Facility Air Permit Number 4911-103-0014-V-01-0[16]
- Final Permit, Fact Sheet Caithness Log Island, LLC Caithness Long island Energy Center-Permit Number PSD-NY-0001
- Final Permit, Statement of Basis, Pine Bluff Energy LLC – Pine Bluff Energy Center – Permit Number 1822-AOP-R1
- Final Permit, Statement of Basis, AECI – Dell Power Plant – Permit Number 1903-AOP-R7
- California Environmental Protection Agency Air Resources Board Website[17]
- Permit issued to Caithness Bellport, LLC Caithness Bellport Energy Center in 2006. Air Compliance Engineer, Joe Cardilly, of the US EPA Region 2 was contacted by the Division per phone conversation on May 17, 2011. According to Mr. Cardilly, facility conducted and submitted a testing report for testing conducted in 2010. Preliminary review of the report appears to indicate compliance with applicable limits. Permit limits were 0.0055 lb/MMBtu (NG firing w/o duct firing) and 0.00066 lb/MMBtu (NG firing w/duct firing)

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

[14] http://www.epa.gov/region4/air/permits/national_ct_list.xls

[15] http://www.georgiaair.org/airpermit/downloads/permits/12700075/psd18569/1270075final.pdf

[16] http://www.georgiaair.org/airpermit/downloads/permits/10300003/psd13404/1030014fp.pdf

[17] http://www.arb.ca.gov/homepage.htm

Georgia EPD performed research to assess whether EPD would accept EPA's request for a lower PM emission limit during natural gas combustion in each new combustion turbine. EPA referenced EPD's Live Oaks Power Plant PSD Permit (4911-127-0075-P-02-0) issued April 8, 2010. The permitted BACT limit for PM10 in Permit No. 4911-127-0075-P-02-0 for natural gas combustion in each combustion turbine and duct burner was set as firing pipeline quality natural gas with a sulfur content not to exceed 0.5 grains per 100 standard cubic feet. The permitted PM10 BACT limit was not 0.0054 lb/MMBtu as noted by EPA Region 4.

Georgia EPD also notes that anticipated PM, PM10, and PM2.5 emission limits may be higher when including condensable PM as required by current federal (and Rule 391-3-1-.02(7)) New Source Review-PSD Program.

Given the high combustion efficiency of the turbines and the firing of clean fuels, the PM, PM10, and PM2.5 emissions should be very low. The Division has determined that the applicant's proposal to use pipeline quality natural gas coupled with ULSD and proper combustion design and operation meets the requirements of BACT for PM, PM10, and PM2.5. The Division will not require the use of lube oil demister vents because of the applicant's adverse comment to this requirement in a letter to the Division dated January 30, 2012.

Upon review of Tables 2-1 and 2-2 of the July 2010 application and the July 1, 2011 application addendum, Georgia EPD believes that the proposed BACT limits can be achieved during periods of SUSD and other periods of normal source operation.

Georgia EPD proposes the following PM, PM10, and PM 2.5 BACT limits:

Fuel Type	PM, PM10, and PM2.5 BACT Proposal
Natural Gas	The Permittee shall only fire pipeline quality natural gas as BACT for PM, PM10, and PM2.5 in each combustion turbine and its paired duct burner. Sulfur content of pipeline quality natural gas shall not exceed 0.5 grains per 100 standard cubic feet.
Fuel Oil	<u>W/O duct firing:</u> 0.0153 lb/MMBtu, including periods of SUSD, on a 3-hour average <u>W/ duct firing: with NG</u> 0.0103 lb/MMBtu, including periods of SUSD, on a 3-hour average
NA	Operation of duct firing will be limited to 4,000 hours during any twelve consecutive months per duct burner. Limit fuel oil firing to 1,000 hours during any twelve consecutive months.

The compliance determination method will be the applicable reference test method.

PSD Avoidance for Sulfur Dioxide

The majority of the project's SO_2 and SAM emissions will come from the combustion turbines and duct burners. Applicable state regulatory mechanisms imposes the following SO_2 requirements which generates potential emissions greater than 40 tpy:

Pollutant	Standard	Regulatory Citation	PTE for SO2 (tpy)
SO_2 from Combustion Turbines Or Total Potential Sulfur Emissions from Combustion Turbines	0.90 lb SO_2/MW-hr 0.060 lb SO_2/MMBtu	40 CFR 60.4330(a)(1) 40 CFR 60.4330(a)(2)	162 Note 1 119.70 Note 2
Limit sulfur content of natural gas	0.5 grains per 100 dscf	40 CFR 52.21(j)	26.34 Note 3 Note 5
Limit fuel oil sulfur content	15 ppm or 0.0015 percent sulfur by weight	40 CFR 52.21(j)	3.15 Note 4 Note 5
SO_2 from Combustion Turbines	0.8 lb/MMBtu	Rule 391-3-1-.02(2)(g)	1,569
Maximum Fuel Sulfur Content from each DB	3.0 weight percent sulfur	Rule 391-3-1-.02(2)(g)	NA

Note 1: SO_2 per CT/HRSG = (0.90 lb/MW-hr)*(1,000 hrs/yr)*(180 MW)*(1 ton/2000 lb)
SO_2 per CT/HRSG = 81 tpy
SO_2 for power block = (81 tpy)*(2) = 162 tpy, per fuel oil combustion

Note 2: SO_2 per CT/HRSG = (0.060 lb SO_2 lb/MMBtu)*(1,995.0 MMBtu/hr-CT)*(1,000 hrs/yr)*(1 ton/2000 lb)
SO_2 per CT/HRSG = 59.85 tpy
SO_2 for power block = (59.85 tpy)*(2) = 119.70 tpy

Note 3: SO_2 per CT/HRSG = (0.5 grains S/100 dscf NG)*(1 lb/7000grains)*(64 lb-mole SO_2/ 32 lb-mole)*(1 ton/2000 lb)*[(1995.0 MMBtu/hr-CT)*(scf/0.001050 MMBtu)*(8,760 hrs/yr) + (470 MMBtu/hr-DB)*(scf/0.001050 MMBtu)*(4,000 hrs/yr)]

SO_2 per CT/HRSG = (7.1428 e-10 tons SO2/dscf)*[(16.644 e09) scf/yr + 1.790476 e09 scf/yr]
SO_2 per CT/HRSG = 13.17 tpy
SO_2 for power block = (13.17 tpy)*(2) = 26.34 tpy

Note 4: SO_2 per CT/HRSG = (0.000015 lb S/lb fuel oil)*(64 lb-mole SO_2/32 lb-mole S)*(7.05 lb fuel oil/gal fuel oil*(2,085.6 MMBtu fuel oil/hr-CT)*(gal fuel oil/0.14 MMBtu)*(1,000 hrs/yr)*(1 ton/2000 lb)

SO_2 per CT/HRSG = 1.57 tpy
SO_2 for power block = (1.57 tpy)*(2) = 3.15 tpy

Note 5:

a. Applicant assumed an SO_2 to SAM conversion ratio of 4.66 SO_2:1 SAM for NG combustion per Table 2-1 of the application.

b. Applicant assumed an SO_2 to SAM conversion ratio of 5.16 SO_2: 1 SAM for ULSD combustion

Potential SAM emissions will remain below the PSD significant emission threshold of 7 tpy with the limits imposed on fuel sulfur content.

The applicant's proposal includes the following limitations which enable potential SO_2 and sulfuric acid mist emissions to remain below the PSD significant thresholds:

- Limit fuel oil combustion in each turbine to 1,000 hours per year.
- Limit sulfur content of fuel oil to 15 ppm.
- Limit sulfur content of natural gas to 0.5 grains per 100 dscf.

Greenhouse Gases (GHG) Emissions

Top-Down BACT Alternatives: The applicant identified and performed detailed discussion of the following GHG control technology for natural gas or fuel oil combustion in each combustion turbine and duct burner in application updates dated March 22, 2011 and August 3, 2011. Georgia EPD supports the applicant's findings.

Energy Efficiency

- Energy efficiency;
- Carbon capture and storage (CCS)
- Add-on controls
- Combination of energy efficiency and add-on controls.

Technical Feasibility Analysis: The following table summarizes the March 2011 submittal discussion on eliminating technically infeasible options. For a detailed discussion, please see pages six through nine of Attachment A of the March 22, 2011 submittal found in Appendix B. Georgia EPD supports the applicant's findings.

Control Technology	Considered Technically Feasible	Reason for Decision
Energy Efficiency	Yes	Considered Technology for a large combined cycle gas turbine unit.
Carbon Capture and Storage	No	Logistical barriers prevent institution of this control technology.
Oxidation Catalyst	Yes	Considered Technology for a large combined cycle gas turbine unit.

Ranking the Technically Feasible Alternatives: The March 2011 submittal indicates energy efficiency as the only technically feasible control technologies. A ranking is therefore, was not presented.

The BACT Emission Standard Analysis: In its March 2011 submittal, Effingham evaluated technically feasible combustion control technologies for the combined cycle units. The control technologies evaluated, verbatim as described in this document, are as follows:

Under Step 4 of the top-down BACT analysis, economic, energy, and environmental impacts must be evaluated for each option remaining under consideration.

The "top" control option should be established as BACT unless the applicant demonstrates, and the permitting authority agrees, that the energy, environmental, or economic impacts justify a conclusion that the most stringent technology is not "achievable" in that case. If the most stringent technology is eliminated in this fashion, then the next most stringent alternative is considered, and so on.

Where GHG control strategies affect emissions of other regulated pollutants, EPA recommends that applicants should consider the potential trade-offs between emissions of GHGs and emissions of other regulated NSR pollutants. For example, controlling CO, VOC, or CH_4 emissions with an oxidation catalyst system creates GHG emissions in the form of CO_2. But because of the higher global warming potential of CH_4, there will be a reduction in global warming potential. Energy efficiency improvements generally reduce emissions of all pollutants resulting from combustion processes, so no significant tradeoffs in emissions expected from energy efficiency improvements.

The proposed CTs at the Effingham Power plant will be operating at the combined-cycle mode, which is more energy efficient than simple cycle. Therefore, no additional improvements are necessary.
The CCS option was eliminated in Step 2 as not technically feasible for the project. Although EPA considers CCS as available, it is not commercially available. Indeed, EPA recognizes that at present CCS is an expensive technology, largely because of the costs associated with CO_2 capture and compression. In the Guidance, EPA states that even if not eliminated in Step 2 of the BACT analysis, on the basis of the current costs of CCS, CCS is more likely to be eliminated from consideration in Step 4 of the BACT analysis, even in some cases where underground storage of the captured CO_2 near the power plant is feasible.

Applicant's GHG BACT Selection: For a detailed discussion on the BACT selection for GHG emissions from the combustion turbines, see pages nine through 12 of Attachment A of the March 2011 submittal. Effingham proposed the use of natural gas and distillate fuel oil as backup and a combined cycle configuration for the project as BACT. According to Effingham's March 2011 submittal, a numerical mission limit is not necessary or appropriate for GHG emissions based on the project's design and fuel use.

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

- USEPA RACT/BACT/LAER Clearinghouse[18] - **Appendix H** of this document specifies the BACT search conducted for this application by Georgia EPD.
- California Air Pollution Control Officers Association's (CAPCOA) BACT Clearinghouse[19]
- National Combustion Turbines List (October 5, 2010)[20]
- EPA's BACT Guidance for Greenhouse Gases from Stationary Sources (November 22, 2010)[21]
- US EPA PSD and Title V Permitting Guidance for Greenhouse Gases (March 2011)[22]

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

[19] http://www.arb.ca.gov/bact/bact.htm

[20] http://www.epa.gov/region4/air/permits/national_ct_list.xls

[21] http://www.fas.org/sgp/crs/misc/R41505.pdf

- Final Permit, Statement of Basis, Additional Statement of Basis, and Responses to Comments for Russell City Energy Center Air Permit Number Permit Application No. 15487[23]
- California Environmental Protection Agency Air Resources Board Website[24]

The applicant's proposal does not satisfy BACT because the applicant did not propose a numerical emission standard. Emissions of GHGs as CO_{2e} can be computed using project fuel usage rates. Georgia EPD computed a CO_{2e} BACT emission rate as follows:

GHG pollutant rate in tons per hour are taken from the application updates dated November 22, 2010 and March 22, 2011 (Table A-1) of the applicant's March 22, 2011 update. These hour emission rates are multiplied by the applicable hours per year for each CT (including SUSD) while firing natural gas; 1,000 hours per year for each CT while firing fuel oil; 4,000 hours per year for each DB while firing natural gas.

Operating Scenario	CO_{2e} (tons per year)
Combustion Turbines firing natural gas- each	863,953
Combustion Turbines firing fuel oil, with fuel oil combustion limited to 1,000 hours per CT. Emission limit is per CT	159,603
Each Duct Burner firing natural gas, with duct burner operation limit to 4,000 hours per DB. Emission limit is per DB	111,837

Compliance with these emission limits will be based on fuel usage and GHG emission factors used in Application No. 19810.

4.2 Auxiliary Boiler

The auxiliary boiler has a heat input capacity of 17 MMBtu/hr, and will be limited to a total of 2,500 hours per twelve consecutive months. According to Application 19810, this boiler will be used to provide auxiliary steam to the steam cycle and shorten the cold and warm start duration during the startup and shutdown sequences of the proposed combustion turbines. Primary emissions from the auxiliary boiler are nitrogen oxides, particulate matter (PM, PM10, and PM2.5), carbon monoxide, volatile organic compounds, and greenhouse gases.

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[22] http://www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf

[23] http://www.baaqmd.gov/Home/Divisions/Engineering/Public%20Notices%20on%20Permits/2009/080309%2015487/Russell%20City%20Energy%20Center.aspx

[24] http://www.arb.ca.gov/homepage.htm

NO_x, CO, VOC, PM, PM_{10}, $PM_{2.5}$, GHG Emissions

Applicant's Proposal

Application 19810 (July 2010) did not include a detailed top-down analysis discussion for the auxiliary boiler. For the specific review conducted by Effingham, see page 48 of Application 19810. The applicant proposes to limit the hours of operation of the auxiliary boiler to 2,500 hours per year. Based on emissions calculation presented in Table 2-7 of the application, the new auxiliary boiler will potentially emit about 2 tpy of NOx, 2 tpy of CO, 0.11 tpy of VOC, and 0.15 tpy of PM (PM, PM10, PM2.5) emissions. The applicant based these potential emissions on EPA's AP-42 emission factors.

The applicant submitted a top-down analysis for GHG emissions to Georgia EPD on August 3, 2011. In summary, Effingham proposed the institution of the proposed operating hours limit and use of only pipeline quality natural gas as sufficient for GHG BACT for the auxiliary boiler. The applicant also provided a potential GHG emission rate (CO_{2e}) of approximately 2,486 tons per year for the auxiliary boiler burning pipeline quality natural gas with an operational limit of 2,500 hours per year.

In summary, Effingham proposed the following BACT limits for the applicable pollutants emitted from the auxiliary boiler:

Pollutant	Control Option	State and Federal Legal Citation	BACT Proposal
NOx	Low NOx Burner	40 CFR 52.21(j)	0.098 lb/MMBtu
CO	Good Combustion Practice	40 CFR 52.21(j)	0.082 lb/MMBtu
VOC	Good Combustion Practice	40 CFR 52.21(j)	0.0052 lb/MMBtu
PM, PM10, PM2.5	Good Combustion Practice	40 CFR 52.21(j)	Use of pipeline quality natural gas with a sulfur content of 0.5 grains per 100 standard cubic feet. 0.0072 lb/MMBtu
CO_{2e}	Good Combustion Practice	40 CFR 52.21(j)	Use of pipeline quality natural gas with a sulfur content of 0.5 grains per 100 standard cubic feet. 2,528 tpy

EPA noted in their letter to Georgia EPD, dated June 7, 2011, that facilities with auxiliary boilers emitted NOx have a limit as low as 0.011 lb/MMBtu (*e.g.,* CPV St. Charles, MD); boilers emitting PM have limits as low as 0.0033 lb/MMBtu; and CO limits of 0.02 lb/MMBtu. EPA also noted that based on review of the available information, these lower limits are technically feasible and should be considered as an option in the BACT analysis.

EPD Review – NO_x, CO, VOC, PM, PM_{10}, $PM_{2.5}$, GHG Control
Georgia EPD is proposing the following BACT for the auxiliary boiler.

BACT Summary for the Auxiliary Boiler

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
NO_x, CO, VOC, PM, PM_{10}, $PM_{2.5}$, CO_{2e}	Baseline	2,500 hours of operation Use of pipeline quality natural gas with a sulfur content not to exceed 0.5 grains per 100 standard cubic feet.	12 consecutive months	Nonresettable Operating Hours Meter Fuel monitoring
NO_x	LNB	0.098 lb/MMBtu	3-hour averaging period	Reference Test Method
CO_{2e}		2,528 tpy	12 consecutive months	Recordkeeping based on fuel usage, GHG emission factors and Global Warming Potential
CO	Good Combustion Practice	0.082 lb/MMBtu	3-hour averaging period	Reference Test Method

4.3 Fuel Gas Heater

The fuel gas heater has a heat input capacity of 8.75 MMBtu/hr. According to Application 19810, this heater is required to ensure that the natural gas supplied to the combustion turbines meets the condition specifications of the gas turbine manufacturer. Primary emissions from the auxiliary boiler are nitrogen oxides, particulate matter (PM, PM10, PM2.5), carbon monoxide, volatile organic compounds, and greenhouse gases.

NO_x, CO, VOC, PM, PM_{10}, $PM_{2.5}$, GHG Emissions

Applicant's Proposal

Application 19810 (July 2010) did not include a detailed top-down analysis discussion for the fuel pre-heater. For the specific review conducted by Effingham, see page 49 of Application 19810. The proposed fuel gas heater will be fired by pipeline quality natural gas with maximum sulfur content limited to 0.5 grains per 100 standard cubic feet.

Based on emissions calculation presented in Table 2-6 of the application, the new fuel gas heater will potentially emit about 1.9 tpy of NOx, 3.1 tpy of CO, 0.20 tpy of VOC, and 0.3 tpy of PM (PM, PM10, PM2.5) emissions. The applicant based these potential emissions on EPA's AP-42 emission factors.

The applicant submitted a top-down analysis for GHG emissions to Georgia EPD on August 3, 2011. In summary, Effingham proposed the institution of the proposed operating hours limit and use of only pipeline quality natural gas as sufficient for GHG BACT for the auxiliary boiler. The applicant also provided a potential GHG emission rate (CO_{2e}) of approximately 4,482 tons per year for the fuel gas heater burning pipeline quality natural gas.

In summary, Effingham proposed the following BACT limits for the applicable pollutants emitted from the fuel gas heater:

Pollutant	Control Option	State and Federal Legal Citation	BACT Proposal
NOx	Low NOx Burner	40 CFR 52.21(j)	0.05 lb/MMBtu
CO	Good Combustion Practice	40 CFR 52.21(j)	0.082 lb/MMBtu
VOC	Good Combustion Practice	40 CFR 52.21(j)	Use of pipeline quality natural gas with a sulfur content not to exceed 0.5 grains per 100 standard cubic feet.
PM, PM10, PM2.5	Good Combustion Practice	40 CFR 52.21(j)	Use of pipeline quality natural gas with a sulfur content of 0.5 grains per 100 standard cubic feet.
CO_{2e}	Good Combustion Practice	40 CFR 52.21(j)	Use of pipeline quality natural gas with a sulfur content of 0.5 grains per 100 standard cubic feet. 4,560 tpy

EPD Review – NO_x, CO, VOC, PM, PM_{10}, $PM_{2.5}$, GHG Control

The maximum CO_2 equivalent emissions from the fuel gas preheater are approximately 4,560.49 short tons as calculated from data provided by the applicant in their November 22, 2010 submittal.

Georgia EPD is proposing the following BACT for the fuel gas pre-heater.

Georgia EPD BACT Summary for the Fuel Gas Pre-Heater

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
NO_x	Good Combustion Practice	Use of pipeline quality natural gas with a fuel sulfur content not to exceed 0.5 grains per 100 standard cubic feet	3-hour averaging	Reference Test Method
CO	Good Combustion Practice	Use of pipeline quality natural gas with a fuel sulfur content not to exceed 0.5 grains per 100 standard cubic feet	3-hour averaging	Reference Test Method
CO_{2e}	Good Combustion Practice pipeline quality natural gas	4,560 tpy	twelve consecutive months	Record keeping based on fuel usage, GHG emission factors and GHG Global Warming Potentials

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
VOC, PM, PM10, PM2.5	Baseline	Use of pipeline quality natural gas with a fuel sulfur content not to exceed 0.5 grains per 100 standard cubic feet	NA	Fuel monitoring

4.4 Cooling Towers

A cooling tower will be used to provide cooling water to the condensing steam turbine. It will be comprised of 10 cells. A separate cooling tower, comprised of 6 cells, will be used for the inlet chiller system. The towers will have mechanical draft counter flow design and equipped with high efficiency drift eliminators. The drift eliminators will use inertial separation caused by airflow direction changes to remove water droplets from the air stream exhausting from the cooling tower.

PM, PM_{10}, $PM_{2.5}$ Emissions

Applicant's Proposal

Application 19810 did not include a detailed top-down analysis discussion for the cooling towers. For the specific review conducted by Effingham, see pages 49 and 50 of Application 19810. In summary, Effingham proposed using high-efficient drift eliminators with a drift rate of 0.001 percent as BACT for the cooling towers. EPA commented adversely on the applicant's proposed BACT for the cooling towers saying "The applicant should elaborate why a drift eliminator with a 0.0005% drift rate is cost prohibitive". The applicant responded in an application update dated August 3, 2011. The applicant did not provide any cost data. The applicant relied on the less restrictive drift elimination because Effingham County is classified as attainment/unclassifiable for PM10 and PM2.5.

EPD Review – PM, PM_{10}, $PM_{2.5}$ Control

In addition to reviewing the permit application and supporting documentation, the Division has performed independent research of the PM, PM_{10}, $PM_{2.5}$ BACT analysis and used the following resources and information:

- USEPA RACT/BACT/LAER Clearinghouse[25]

Appendix I of this document presents Georgia EPD's BACT review for the cooling towers.

This BACT review resulted in the determination of a drift eliminator effectiveness of 0.0005% for several permits issued in the past two years, including one issued recently by Georgia EPD. Furthermore, the reason listed Application 19810 for not imposing a drift eliminator effectiveness of 0.0005% is cost. As pointed out in EPA Comments, included in **Appendix B**, Effingham did not elaborate why a drift eliminator with 0.0005% drift rate is cost prohibitive. Therefore, the institution of a drift eliminator with an effectiveness of 0.0005% is deemed appropriate for BACT. Therefore, the Division has determined that Effingham's proposal to use a mass flow rate of drift to meeting a drift eliminator effectiveness of 0.001% to minimize the emissions of particulate matter from the cooling towers does not constitute BACT. A drift eliminator effectiveness of 0.0005% is considered BACT for each cooling tower.

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

Conclusion – PM, PM_{10}, $PM_{2.5}$ Control

The BACT selection for the cooling towers is summarized below in Table 4-10:

Georgia EPD BACT Summary for the Cooling Towers

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
PM, PM_{10}, $PM_{2.5}$	Drift Eliminators (per cooling tower)	Mass flow rate of drift to meeting a drift eliminator effectiveness of 0.0005%	-	Vendor Certification and Specification

4.5 Fuel Oil Storage Tank

The facility will use a 2,350,000-gallon fixed roof fuel oil storage tank to store fuel used at the facility. The tank will be equipped with conservation vent valves which include both pressure relief valves and vacuum relief valves. Primary emissions from this equipment are VOC.

VOC Emissions

Applicant's Proposal
Application 19810 did not include a detailed top-down analysis discussion for the fuel oil storage tank. For the specific review conducted by Effingham, see page 50 of Application 19810. In summary, Effingham proposed conservation vent values as BACT for the fuel oil storage tank.

EPD Review – VOC Control
The Division has determined that the use conservation vents and proper maintenance and operating practices as specified by the manufacturer shall be considered as BACT. In addition, the tank must be equipped with submerged fuel fill pipes to filling process. Operating practices shall be maintained in a manual and updated as applicable. These manuals shall be made available for Division review upon request.

The BACT selection for the fuel oil storage tank is summarized below:

Georgia EPD BACT Summary for the Fuel Oil Storage Tank

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
VOC	Conservation vents and proper operating and maintenance practices as specified by the manufacturer for fuel storage tank	-	-	Monitoring

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
VOC	Submerged fuel fill pipes on the fuel storage tank	-	-	-

5.0 TESTING AND MONITORING REQUIREMENTS

Combined Cycle Units

Each combined-cycle unit is subject to BACT requirements for NOx, CO, VOC, PM, PM10, PM2.5, and GHG emissions and for visible emissions (opacity); 40 CFR 60 Subpart KKKK for SO_2 and NOx emissions; Georgia Rules 391-3-1-.02(2)(d) for NOx, PM and opacity; Georgia Rules 391-3-1-.02(2)(g) for fuel sulfur content; and the Acid Rain Regulations for SO_2 emissions. The PSD emission standards for PM and NOx and fuel sulfur content subsume the emission standards specified by Georgia Rules 391-3-1-.02(2)(d) and (g) for PM and NOx emissions (for new duct burner) and fuel sulfur content (for new duct burners and combustion turbines). The PSD emission standard for NOx from the combustion turbine/duct burner combined stacks (CTG3/DB3 and CTG4/DB4) subsume the emission standard for NOx per NSPS KKKK as the numerical standard and averaging period specified by PSD is more stringent than that specified by NSPS KKKK.

Requirements for NOx

NSPS Subpart KKKK requires an initial NOx performance test using Method 7E. Continuous compliance with the NOx emission limitations of Subpart KKKK will be demonstrated with a NOx CEMS in keeping with 40 CFR 60.4335(b)(1), 60.4304(b)(1), and 60.4345. Each NOx CEMS must be installed and certified according to Performance Specification 2 of 40 CFR Part 60, Appendix B, except that the 7-day calibration drift is to be based on unit operating days, not calendar days.

Three-hour rolling NOx emission measurements by the NOx CEMS satisfy the periodic monitoring requirement for the non-NSPS NOx emission limits. The three-hour rolling NOx emission measurements will also satisfy the Subpart KKKK NOx emission limits, even though those limits are based on a 30-day rolling average because, for the same numerical value, an emission limit based on a three-hour average is more stringent than one based on a 30-day average. Therefore, so long as the three-hour NOx CEMS average concentrations are less than either 15 ppm or 42 ppm, as applicable, the Division concludes that the NOx CEMS can be used to demonstrate continuous compliance with the Subpart KKKK NOx emission limits.

The Acid Rain regulations require that the NOx mass emission rate from each combustion turbine and its paired duct burner be measured and recorded. The Permittee must ensure that the NOx CEMS meets all applicable criteria of 40 CFR Part 75, including the general requirements of 40 CFR 75.10; the specific provisions of 40 CFR 75.12; the equipment, installation, and performance specifications in Appendix A; and the quality assurance and quality control procedures in Appendix B. The Clean Air Interstate Rule (CAIR) also requires the monitoring of NOx mass emissions. Satisfaction of the 40 CFR Part 75 Acid Rain NOx monitoring requirements mentioned above, including Part 75, Subpart H (NOx Mass Emissions Provisions), will assure compliance with the CAIR monitoring requirements.

The applicant does not want the NOx CEMS to be the continuous compliance determination method for the short-term and annual PSD NOx limit.

The following table specifies the regulatory requirements:

Fuel Type	Emission Standard and Citation	Testing Requirements	Monitoring Requirements
Natural Gas Or Fuel Oil	<u>NSPS KKKK</u> 15ppmvd @ 15% oxygen or (0.43 lb/MW-hr of useful output) on a 30-unit operating day basis. The NSPS KKKK emission limit for NOx is subsumed by the PSD BACT Limit <u>BACT Limit</u> 2.0 ppmvd@15% oxygen on a 3-hour average <u>NSPS KKKK</u> 42 ppmvd @ 15% oxygen (1.3 lb/MW-hr of useful output) on a 30- unit operating day basis. The NSPS KKKK emission limit for NOx is subsumed by the PSD BACT Limit. <u>BACT Limit</u> 10.0 ppmvd @ 15% oxygen on a 3-hour basis.	<u>40 CFR 60.8</u> Initial performance test for NOx in accordance with 40 CFR 60.4400. <u>NSPS KKKK</u> NOx CEMS is the compliance determination method. <u>PSD</u> The applicable reference test method	<u>40 CFR 60.4335(b)</u> Install, certify, maintain, and operate a CEMS consisting of a NOx monitor and a diluent gas to determine the hourly NOx emission rate in ppm or lb/MMBtu. This option corresponds to the concentration limit. <u>40 CFR 60.4345</u> This citation specifies the requirements for the NOx CEMS. <u>40 CFR 60.4350</u> This citation specifies an excess emissions on a 30 unit operating day rolling average basis, as described in 40 CFR 60.4380(b)(1). <u>Acid Rain</u> The NOx CEMS must meet the requirements of 40 CFR Part 75.

Requirements for CO:
Compliance with the BACT CO emission limitations for each combustion turbine and its paired duct burner (emission unit ID Nos. CTG3/DB3 and CTG4/DB4) must be demonstrated by an initial performance test using Method 10, <u>the method for compliance determination</u>. For each of the combined-cycle systems (emission unit ID Nos. CTG3/DB3 and CTG4/DB4), separate tests must be conducted while burning natural gas and fuel oil in the combustion turbines. Because the Division is requiring the use of CO CEMS (discussed below), annual performance testing is not required.

To reasonable assure compliance with the BACT CO emissions limitations, the proposed permit requires a CO CEMS for the periodic monitoring of the discharge from each combustion turbine and its paired duct burner (emission unit ID Nos. CTG3/DB3 and CTG4/DB4). Each CO CEMS is also used to determine the mass emissions on an annual basis from each combined-cycle system to verify compliance with the PSD annual CO limits. Each CO CEMS must be installed and certified according to Performance Specification 4A of 40 CFR Part 60, Appendix B, except that the 7-day calibration drift is to be based on unit operating days, not calendar days.

Requirements for VOC:
The permit includes an initial performance test for VOC emissions from each combustion turbine and its paired duct burner to verify compliance with the VOC BACT emission standard. Method 25A performance testing will be the compliance determination method for VOC. There is no reliable and readily available method for long-term, continuous monitoring of VOC emissions from the type of fuel-burning equipment proposed by the Permittee. Each combined-cycle system (emission unit ID Nos. CTG3/DB3 and CTG4/DB4) will be equipped with catalytic oxidation systems to control emissions of both VOC and CO. The Division believes that the VOC emissions from each combined-cycle system (emission unit ID Nos. CTG3/DB3 and CTG4/DB4) will be in compliance with the VOC BACT emission limit as long as the CO emissions from those systems are in compliance with the corresponding CO BACT emission limits. The CO CEMS therefore will also constitute periodic monitoring for VOC.

Requirements for PM, PM10, PM2.5 and Opacity:
The combustion turbine component of each combined-cycle system will only be able to fire pipeline quality natural gas and ultra low sulfur fuel oil. Each of these fuels is a low-ash fuel. Each combustion turbine and each duct burner are designed to achieve highly efficient (complete) combustion. Consequently, the Division believes that each combined-cycle system will emit negligible amounts of particulate matter and visible emissions. Because the magnitude of those emissions are expected to be below their allowable emission levels with no end of pipe control, performance testing or continuous monitoring for PM, PM10, PM2.5 and visible emissions will only be required for fuel oil combustion. Method 9 will be the basis for periodic monitoring of visible emissions when the Division deems necessary. So long as the combined-cycle systems, including their air pollution control devices are properly operated and maintained, the Division is fully assured of acceptable PM, PM10, and PM2.5 emissions without the need for any other periodic monitoring.

Requirements for SO2 Emissions and Fuel Sulfur Content:
The SO2 emissions from the combustion turbine and duct burner combined stack are subject to an NSPS Subpart KKKK emission standard <u>and</u> fuel sulfur content limits for PSD Avoidance purposes.

Per 40 CFR 60.4330(a), as the proposed turbines are to be located in a continental area, the applicant must comply with either paragraphs 60.4330(a)(1) or (a)(2) as the turbines will be permitted to combust only natural gas or ultra low sulfur diesel fuel. The following table specifies the NSPS Subpart KKKK testing and monitoring conditions depending on the form of the emission standard chosen by the applicant:

Fuel Type	Emission Standard and its Citation	Testing Requirements	Monitoring Requirements
Natural Gas Or Fuel Oil	<u>60.4330(a)(1)</u> SO2 $\leq$ 0.090 lb/MW-hr gross output <u>60.4330(a)(2)</u> Total potential sulfur emissions $\leq$ 0.060 lb/MMBtu heat input <u>PSD Avoidance</u> Pipeline quality natural	<u>60.4415</u> Initial performance test in accordance with 60.8 and subsequent performance tests shall be conducted on an annual basis. There are three methodologies that the applicant may use to conduct the performance tests.	<u>60.4360 and 60.4370</u> Monitor the total sulfur content of the fuel being fired in the turbine using total sulfur methods described in 40 CFR 60.4415 or alternative described in 40 CFR 60.4360. Frequency of monitoring is specified by 60.4370 – for

Fuel Type	Emission Standard and its Citation	Testing Requirements	Monitoring Requirements
	gas will be used which contains a fuel sulfur content not to exceed 0.5 grains per 100 standard cubic feet. Fuel oil will be used which contains a fuel sulfur content not to exceed 15 ppm.	<u>Method Option 1:</u> Periodically determine the sulfur content of the fuel combusted in the turbine. <u>Method Option 2:</u> Measure the SO2 concentration in ppm Using specified Reference Test Methods and then calculate the SO2 emission rate in lb/MW-hr gross output. <u>Method Option 3:</u> To show compliance with 60.4330(a)(2) – follow testing requirements specified in 60.4415(a)(3).	natural gas – determine and recorded once per unit operating day or per an approved custom schedule. or <u>60.4365</u> Make a demonstration that the fuel sulfur potential emissions do not exceed 0.060 lb/MMBtu using a current, valid purchase contract, tariff sheet or transportation contract for the fuel specifying that the <u>Option for NG:</u> maximum total sulfur content of natural gas is 20 grains of sulfur or less per 100 standard cubic feet <u>and</u> has potential sulfur emissions of less than 0.060 lb/MMBtu heat input; or using a representative fuel sampling schedule as specified in 60.4365(b). <u>Option for Fuel Oil:</u> Maximum total sulfur content of fuel oil is 0.05 weight percent (500 ppmw) or less <u>and</u> has potential sulfur emissions of less than 0.060 lb/MMBtu ; or using a representative fuel sampling schedule as specified in 60.4365(b).

Requirements of GHG: The permit includes a CO_{2e} emissions limit for each combined combustion turbine and duct burner stack. The applicant will be required to monitor fuel usage (for each fuel type) and compute annual CO_{2e} emissions using the GHG emission factors and global warming potential found in Application 19810.

Requirements of 40 CFR 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, the Division assessed the applicability of 40 CFR 64.5(a)(2).

The following table illustrates the Division's applicability analysis.

Pollutant and Equipment	Pre-Controlled PTE	Subject to a Std? Uses a Control Device?	Subject to Part 64?
NOx			
CT/HRSG	>100 tpy	Yes – PSD Yes - NSPS Yes – SCR	Yes No – Exempt per 40 CFR 64.2(b)(1)(i).
Auxiliary Boiler	<100 tpy	Yes/No	No
Fuel Gas Preheater	< 100 tpy	Yes/No	No
CO			
CT/HRSG	>100 tpy	Yes/Yes (Catalytic Oxidation)	Yes
Auxiliary Boiler	<100 tpy	Yes/No	No
Fuel Gas Preheater	< 100 tpy	Yes/No	No
VOC			
CT/HRSG	<100 tpy	Yes/Yes (Catalytic Oxidation	No
Auxiliary Boiler	< 100 tpy	Yes/No	No
Fuel Gas Preheater	<100 tpy	Yes/No	No
PM, PM10, PM2.5			
CT/HRSG	< 100 tpy	Yes/No	No
Auxiliary Boiler	< 100 tpy	Yes/No	No

Pollutant and Equipment	**Pre-Controlled PTE**	**Subject to a Std? Uses a Control Device?**	**Subject to Part 64?**
Fuel Gas Preheater	<100 tpy	Yes/No	No
SO_2			
CT/HRSG	< 100 tpy	Yes/No	No
Auxiliary Boiler	< 100 tpy	No	No
Fuel Gas Preheater	< 100 tpy	No	No

The combustion turbine and its paired duct burner (emission unit ID Nos. CTG3/DB3 and CTG4/DB4) are subject to the requirements of compliance assurance monitoring (CAM) for NOx and CO emissions as specified in 40 CFR 64. CAM is applicable because the pre-controlled NOx and CO emissions are greater than 100 tpy and the applicant will use a catalytic oxidation unit to control CO emissions and selective catalytic reduction to control NOx emissions.

Ancillary Equipment

Ancillary equipment includes a fuel gas pre-heater, auxiliary boiler, fuel oil storage tank, and cooling towers.

The auxiliary boiler with emission unit ID No. AB2 is subject to PSD BACT for NOx, CO, VOC, PM, PM10, PM2.5, and GHG emissions and opacity; Georgia Rule 391-3-1-.02(2)(d) for PM emissions and opacity; Georgia Rule 391-3-1-.02(2)(g) for fuel sulfur content. The PSD BACT requirements for PM and opacity and fuel sulfur content subsume the requirements of Georgia Rules (d) and (g). The Permittee will fire pipeline quality natural gas in the auxiliary boiler with emission unit ID No. AB2. No performance tests will be required for verifying compliance with emission limits specified in Conditions 3.3.38 and 3.3.39. The Permittee will be required to track fuel usage amounts in order to compute actual GHG emissions from the operation of the boiler with emission unit ID No. AB2. In addition, the Permittee will be required to install and operate a system to continuously monitor the cumulative total hours of operation in order to verify compliance with the operational limit of 2,500 hours during any twelve consecutive months. Lastly, the Permittee will be required to track the fuel sulfur content of the pipeline quality natural gas combusted in the boiler with emission unit ID No. AB2 in accordance with Condition 6.2.15.

The fuel gas pre-heater with emission unit ID No. FP2 is subject to PSD BACT for NOx, CO, VOC, PM, PM10, PM2.5, and GHG emissions and opacity. Georgia Rule 391-3-1-.02(2)(d) for PM emissions and opacity; Georgia Rule 391-3-1-.02(2)(g) for fuel sulfur content. The PSD BACT requirements for PM and opacity and fuel sulfur content subsume the requirements of Georgia Rules (d) and (g). The Permittee will fire pipeline quality natural gas in the fuel gas pre-heater with emission unit ID No. FP2 which represents BACT for NOx, CO, VOC, PM, $PM_{10,}$ and $PM_{2.5}$. The Permittee will be required to track fuel usage amounts in order to compute actual GHG emissions from the operation of the heater with emission unit ID No. FP2. Lastly, the Permittee will be required to track the fuel sulfur content of the pipeline quality natural gas combusted in the boiler with emission unit ID No. FP2 in accordance with Condition 6.2.15.

6.0 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.

NSPS KKKK defines the following excess emissions that apply to this project and permit: These definitions are included in New Condition 6.1.8.

- 40 CFR 60.4350 defines the NSPS KKKK averaging period for the NSPS NOx emission standard as a 30 unit operating day rolling average since the project consists of a combined cycle with heat recovery. 40 CFR 60.4380(b) defines an excess emission as any unit operating period in which the 30 unit operating day rolling average NOx emission rate from each combined combustion turbine/duct burner stack defined in Condition 3.3.16 exceeds 15 ppmvd@ 15% oxygen (while burning natural gas) or 42 ppmvd @ 15% oxygen (while burning fuel oil).
- NSPS KKKK specifies an SO_2 emission standard that can be specified one of two ways (SO_2 emissions as lb/MW-hr useful output or total sulfur potential emissions in lb SO_2/MMBtu). The Permittee can verify compliance with the NSPS KKKK SO_2 emission standard via fuel sulfur content monitoring and performance testing. 40 CFR 60.4385 defines SO_2 excess emissions based on fuel sulfur content monitoring.

Exceedances are defined in New Condition 6.1.8 as follows:

- <u>Exceedance of any of the operational limits specified by PSD:</u>
  (1) 2,500 hours during any twelve consecutive months for boiler with emission unit ID AB2;

  (2) 1,000 hours during any twelve consecutive months while firing fuel oil in each combustion turbine with emission unit ID Nos. CTG3 and CTG4; and

  (3) 4,000 hours during any twelve consecutive months for each duct burner with emission unit ID Nos. DB3 and DB4.

  (4) 1,099 hours during any twelve consecutive months for startup of each turbine with emission unit ID No. CTG3 and CTG4.

- <u>Exceedance of any of the following emission limits while firing natural gas for purposes of PSD:</u>
  (1) 2.0 ppmvd @15% oxygen on a 3-hour average basis for NOx emissions from each combined combustion turbine/duct burner stack (emission unit ID Nos. CTG3/DB3 and CTG4/DB4);

  (2) 2.0 ppmvd @ 15% oxygen on a 3-hour average basis for CO emissions from each combined combustion turbine/duct burner stack (emission unit ID Nos. CTG3/DB3 and CTG4/DB4);

  (3) 210 tons of NOx emissions during any twelve consecutive months from each combined combustion turbine/duct burner stack (emission unit ID Nos. CTG3/DB3 and CTG4/DB4);

  (4) 236 tons of CO emissions during any twelve consecutive months from each combined combustion turbine/duct burner stack (emission unit ID Nos. CTG3/DB3 and CTG4/DB4);

(5) 863,953 tons of CO_{2e} emissions during any twelve consecutive months from each combustion turbine with emission unit ID Nos. CTG3 and CTG4;

(6) 111,837 tons of CO_{2e} emissions during any twelve consecutive months from each duct burner with emission unit ID Nos. DB3 and DB4;

(7) 2,528 tons of CO_{2e} emissions during any twelve consecutive months from boiler with emission unit ID No. AB2;

(8) 4,560 tons of CO_{2e} emissions during any twelve consecutive months from fuel gas heater with emission unit ID No. FP2; and

- <u>Exceedance of any of the following emission limits while firing fuel oil for purposes of PSD are defined in Condition 6.1.8:</u>
  (1) 10.0 ppmvd @ 15% oxygen on a 3-hour average basis for NOx emissions from each combined combustion turbine/duct burner stack (emission unit ID Nos. CTG3/DB3 and CTG4/DB4);

  (2) 2.0 ppmvd @ 15% oxygen on a 3-hour average basis for CO emissions from each combined combustion turbine/duct burner stack (emission unit ID Nos. CTG3/DB3 and CTG4/DB4);

  (3) 67 tons of NOx emissions during any twelve consecutive months from each combined combustion turbine/duct burner stack (emission unit ID Nos. CTG3/DB3 and CTG4/DB4);

  (4) 46 tons of CO emissions during any twelve consecutive months from each combined combustion turbine/duct burner stack (emission unit ID Nos. CTG3/DB3 and CTG4/DB4);

  (5) 159,603 tons of CO_{2e} emissions during any twelve consecutive months from each combined combustion turbine/duct burner stack (emission unit ID Nos. CTG3/DB3 and CTG4/DB4).

- <u>Exceedance of any of the following fuel sulfur content limits for PSD and PSD Avoidance are defined in Condition 6.1.8:</u>
  (1) a natural gas sulfur content which exceeds 0.5 grains per 100 standard cubic feet; and

  (2) a fuel oil sulfur content which exceeds 15 ppm (0.0015 weight percent sulfur).

There are no excursions to be reported as part of this permit.

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 below 236 tons (NG) and 46 tons (fuel oil) 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 below 236 tons (NG) and 46 tons(fuel oil) during any twelve consecutive must be reported as an exceedance.

Verification of Compliance with GHG Emission Rates

Compliance with the twelve month rolling total GHG emission rates (expressed as CO_{2e}) from the applicable equipment is to be tracked using fuel usage data and emission factors and global warming potentials found in Application No. 19810. The Permittee is required to retain monthly records (including calculations).

Verification of Compliance with Fuel Sulfur Content Limits

The permit will limit natural gas fuel sulfur content to 0.5 grains per 100 standard cubic feet per PSD BACT and for PSD Avoidance purposes for SO_2 and Sulfuric Acid Mist emissions. The Permittee shall maintain records specifying the natural gas characteristics (including fuel sulfur content) using a current valid purchase contract, tariff sheet or transportation contract to verify compliance.

The permit will limit fuel oil sulfur content to 15 ppm (or 0.0015 weight percent sulfur) per PSD BACT and for PSD Avoidance purposes for SO_2 and Sulfuric Acid Mist emissions. The Permittee shall maintain fuel oil receipts obtained from the fuel supplier or by Division approved analyses to verify compliance.

The PSD BACT and PSD Avoidance fuel sulfur limits subsume the NSPS KKKK fuel sulfur limit for natural gas and fuel oil. Therefore compliance with the fuel sulfur limits specified by NSPS KKKK will not be required in the permit.

7.0 AMBIENT AIR QUALITY REVIEW

An air quality analysis is required to determine the ambient impacts associated with the construction and operation of the proposed modifications. The main purpose of the air quality analysis is to demonstrate that emissions emitted from the proposed modifications, in conjunction with other applicable emissions from existing sources (including secondary emissions from growth associated with the new project), will not cause or contribute to a violation of any applicable National Ambient Air Quality Standard (NAAQS) or PSD increment in a Class I or Class II area. NAAQS exist for NO_2, CO, $PM_{2.5,}$ PM_{10}, SO_2, Ozone (O_3), and lead. PSD increments exist for SO_2, NO_2, and PM_{10}. A PSD increment will apply for $PM_{2.5}$ on October 20, 2011.

The proposed project at the Effingham triggers PSD review for NO_x, CO, VOC, GHGs, PM, $PM_{2.5,}$, and PM_{10}. An air quality analysis was conducted to demonstrate the facility's compliance with the NAAQS and PSD Increment standards for NO_x, CO, $PM_{2.5,}$ and $PM_{10.}$ An additional analysis was conducted to demonstrate compliance with the Georgia air toxics program. This section of the application discusses the air quality analysis requirements, methodologies, and results. Supporting documentation may be found in the Air Quality Dispersion Report of the application and in the additional information packages.

Modeling Requirements

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

The proposed project will cause net emission increases of NO_x, CO, VOC, GHGs, PM, $PM_{2.5}$, and PM_{10} that are greater than the applicable PSD Significant Emission Rates. Therefore, air dispersion modeling analyses are required to demonstrate compliance with the NAAQS and PSD Increment. TRS and VOC do not have established PSD modeling significance levels (MSL) (an ambient concentration expressed in either $\mu g/m^3$ or ppm). While TRS does not have established Significant Impact Levels, it does have an ambient monitoring *de minimis* threshold that is concentration-based. Therefore, TRS modeling was conducted to demonstrate that the project impact is below the ambient monitoring *de minimis* concentration.

<u>Significance Analysis: Ambient Monitoring Requirements and Source Inventories</u>
Initially, a Significance Analysis is conducted to determine if the NO_x, CO, VOC, GHGs, PM, $PM_{2.5}$, and PM_{10} emissions increases at the Effingham County Power Plant would significantly impact the area surrounding the facility. Maximum ground-level concentrations are compared to the pollutant-specific U.S. EPA-established Significant Impact Level (SIL). The SIL for the pollutants of concern are summarized in Table 7-1.

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

Under current U.S. EPA policies, the maximum impacts due to the emissions increases from a project are also assessed against monitoring *de minimis* levels to determine whether pre-construction monitoring should be considered. These monitoring *de minimis* levels are also listed in Table 7-1. If either the predicted modeled impact from an emission increase or the existing ambient concentration is less than the monitoring *de minimis* concentration, the permitting agency has the discretionary authority to exempt an applicant from pre-construction ambient monitoring. This evaluation is required for NO_x, CO, $PM_{2.5}$, and PM_{10}.

If any off-site pollutant impacts calculated in the Significance Analysis exceed the SIL, a Significant Impact Area (SIA) would be determined. The SIA encompasses a circle centered on the facility with a radius extending out to (1) the farthest location where the emissions increase of a pollutant from the project causes a significant ambient impact, or (2) a distance of 50 km, whichever is less. All sources within a distance of 50 km of the edge of a SIA are assumed to potentially contribute to ground-level concentrations within the SIA and would be evaluated for possible inclusion in the NAAQS and PSD Increment analyses. EPA promulgated SILs for $PM_{2.5}$ on October 20, 2010 (75 FR 64864-64907). Official SILs for the 1-hour NO_2 and 1-hour SO_2 NAAQS have not been promulgated by EPA.

Table 7-1: Summary of Modeling Significance Levels

Pollutant	Averaging Period	PSD Significant Impact Level (ug/m^3)	PSD Monitoring Deminimis Concentration (ug/m^3)
PM_{10}	Annual	1	--
	24-Hour	5	10
$PM_{2.5}$	Annual	0.3	--
	24-Hour	1.2	4
NO_2	Annual	1	14
	1-Hour	7.5	--
CO	8-Hour	500	575
	1-Hour	2000	--

NAAQS Analysis

The primary NAAQS are the maximum concentration ceilings, measured in terms of total concentration of pollutant in the atmosphere, which define the "levels of air quality which the U.S. EPA judges are necessary, with an adequate margin of safety, to protect the public health." Secondary NAAQS define the levels that "protect the public welfare from any known or anticipated adverse effects of a pollutant." The primary and secondary NAAQS are listed in Table 7-2 below.

Table 7-2: Summary of National Ambient Air Quality Standards

Pollutant	Averaging Period	NAAQS	
		Primary / Secondary (ug/m^3)	Primary / Secondary (ppm)
PM_{10}	Annual	*Revoked 12/17/06	*Revoked 12/17/06
	24-Hour	150 / 150	--
$PM_{2.5}$	Annual	15 / 15	--
	24-Hour	35 / 35	--
NO_2	1-Hour	188/188	--/--
	Annual	100 / 100	0.053 / 0.053
CO	8-Hour	10,000 / None	9 / None
	1-Hour	40,000 / None	35 / None

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

PSD Increment Analysis

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

U.S. EPA has established PSD Increments for NO_X, SO_2, PM_{10}, and $PM_{2.5}$; no increments have been established for CO. The Effingham County Power Plant is located in a Class II area. The PSD Increments are listed in Table 7-3. The $PM_{2.5}$ increments will not apply in this case since the applicant submitted a "complete" application by October 20, 2011.

Table 7-3: Summary of PSD Increments

Pollutant	Averaging Period	PSD Increment	
		Class I (ug/m^3)	Class II (ug/m^3)
PM_{10}	Annual	4	17
	24-Hour	8	30
NO_x	Annual	2.5	25

Modeling Methodology

Details on the dispersion model, including meteorological data, source data, and receptors can be found in EPD's PSD Dispersion Modeling and Air Toxics Assessment Review in Appendix C of this Preliminary Determination and in Section 6.0 of the permit application.

Modeling Results

Table 6-4 shows that the proposed project will not cause ambient impacts of CO and PM_{10} above the appropriate SIL. Because the emissions increases from the proposed project result in ambient impacts less than the SIL, no further PSD analyses were conducted for these pollutants.

However, ambient impacts above the SILs were predicted for the 1-hour NO_2, and 24-hour $PM_{2.5}$ NAAQS, requiring NAAQS and Increment analyses be performed for NO_x and $PM_{2.5}$.

Table 7-4: Class II Significance Analysis Results – Comparison to SILs

Pollutant	Averaging Period	Year	UTM East (km)	UTM North (km)	Maximum Impact (ug/m^3)	SIL (ug/m^3)	Significant?
NO_2	Annual	1990	473300	3571900	0.73	1	No
	1-hour	**	473304	3570731	29.91	7.5	**Yes**
PM_{10}	24-hour	1990	473200	3572000	3.03	5	No
	Annual	1990	473300	3572000	0.22	1	No
$PM_{2.5}$	24-hour	**	473835	3570971	2.385	1.2	**Yes**
	Annual	**	473900	3571000	0.18954	0.3	No
CO	1-hour	1990	473747	3570932	39.88	2000	No
	8-hour	1993	473879	3570992	30.18	500	No

Data for worst year provided only.
**Receptor-specific 5 year average

No PSD increment analysis was performed given that no Increment limits have been promulgated for 1-hr NO_2, and the ones promulgated for $PM_{2.5}$ are not yet in effect. A Full Impact NAAQS Analysis was conducted for the 1-hour NO_2, and 24-hour $PM_{2.5}$ NAAQS.

Significant Impact Area

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

Based on the results of the Significance Analysis, the distance between the facility and the furthest receptor from the facility that showed a modeled concentration exceeding the corresponding SIL was determined to be 1.64 kilometers for the 24-hr $PM_{2.5}$ modeled concentration and 2.31 kilometers for 1-hr NO_2 modeled concentration. To be conservative, regional source inventories for both of these pollutants were prepared for sources located within 50 kilometers of the facility.

NAAQS and Increment Modeling

The next step in completing the NAAQS and Increment analyses was the development of a regional source inventory. Nearby sources that have the potential to contribute significantly within the facility's SIA are ideally included in this regional inventory. Effingham requested and received an inventory of NAAQS and PSD Increment sources from Georgia EPD. Effingham reviewed the data received and calculated the distance from the plant to each facility in the inventory. All sources more than 60 km outside the SIA were excluded. Per Application Number 19810 (page 62), the screening area extends into four South Carolina counties. The South Carolina Department of Health and Environmental Control (SCDHEC) was contacted by the facility for a list or sources in those counties.

The distance from the facility of each source listed in the regional inventories was calculated, and all sources located more than 60 kilometers from the plant were excluded from the analysis. Additionally, pursuant to the "20D Rule," facilities outside the SIA were also excluded from the inventory if the entire facility's emissions (expressed in tons per year) were less than 20 times the distance (expressed in kilometers) from the facility to the edge of the SIA. In applying the 20D Rule, facilities in close proximity to each other (within approximately 5 kilometers of each other) were considered as one source. Then, any Increment consumers from the provided inventory were added to the permit application forms or other readily available permitting information.

The regional source inventory used in the analysis is included in the permit application and the attached modeling report.

NAAQS Analysis

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

The results of the NAAQS analysis are shown in Table 7-5. For the short-term averaging periods, the impacts are the highest second-high impacts. For the annual averaging period, the impacts are the highest impact. When the total impact at all significant receptors within the SIA are below the corresponding NAAQS, compliance is demonstrated.

Table 7-5: NAAQS Analysis Results

Pollutant	Averaging Period	Year	UTM East (km)	UTM North (km)	Maximum Impact (ug/m^3)	Background (ug/m^3)	Total Impact (ug/m^3)	NAAQS (ug/m^3)	Exceed NAAQS?
NO_2	1-hour	**	472600	3570700	90.77	40	130.77	188	No
$PM_{2.5}$	24-hour	**	472600	3570800	5.02	25	30.02	35	No

Data for worst year provided only.
** 5-year average

As indicated in Table 7-5 above, total modeled impacts at all significant receptors within the SIA are below the corresponding NAAQS.

Increment Analysis

According to Modeling Memorandum in Appendix C, no PSD increment analysis is required given that no Increment limits have been promulgated for 1-hr NO_2, and the ones promulgated for $PM_{2.5}$ are not yet in effect.

Ambient Monitoring Requirements

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

Pollutant	Averaging Period	Year*	UTM East (km)	UTM North (km)	Monitoring De Minimis Level (ug/m^3)	Modeled Maximum Impact (ug/m^3)	Significant?
NO_2	Annual	1990	473300	3571900	14	0.73	No
PM_{10}	Annual	1990	473300	3572000	10	0.22	No
$PM_{2.5}$	24-hour	**	473835	3570971	4	2.385	No
CO	8-hour	1993	473879	3570992	575	30.18	No

Data for worst year provided only
**Averaged over five years

The impacts for NO_X, CO, $PM_{2.5}$, and PM_{10} quantified in Table 7-4 of the Class I Significance Analysis are compared to the Monitoring *de minimis* concentrations, shown in Table 7-1, to determine if ambient monitoring requirements need to be considered as part of this permit action. Because all maximum modeled impacts are below the corresponding de minimis concentrations, no pre-construction monitoring is required for NO_2, PM_{10}, $PM_{2.5}$, or CO.

As noted previously, the VOC *de minimis* concentration is mass-based (100 tpy) rather than ambient concentration-based (ppm or µg/m^3). Projected VOC emissions increases resulting from the proposed modification exceed 100 tpy; however, the current Georgia EPD ozone monitoring network (which includes monitors in the station 13-051-0021 located in Savannah, Chatham County, GA, approximately 32 kilometers from the project site) will provide sufficient ozone data such that no pre-construction or post-construction ozone monitoring is necessary.

Class I Area Analysis

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

The three Class I areas within approximately 200 kilometers of Effingham are the Wolf Island National Wilderness Area, located approximately 101 kilometers south of the facility; Okefenokee National Wilderness Area, located approximately 162 kilometers south of the facility; and Cape Roman National Wilderness Area, located approximately 167 kilometers north of the facility. The U.S. Fish and Wildlife Service (FWS) is the designated Federal Land Manager (FLM) responsible for oversight of all three of these Class I areas.

8.0 ADDITIONAL IMPACT ANALYSES

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

Soils and Vegetation Analysis

The U.S. EPA has developed certain screening concentrations below which it can be reasonably assumed that the soils and vegetation in the vicinity of a proposed project will not experience any adverse effects due to air emissions associated with the project. According to the modeling memorandum including in Appendix C, with regard to the impacts on soils and vegetation analysis, GA EPD considers these requirements to apply to only those criteria pollutants with deterministic NAAQS (those which are assessed in accordance with the Draft 1990 New Source Review Workshop Manual modeling guidance). Thus, 24-hr $PM_{2.5}$ and the 1-hr NO_2 NAAQS do not apply to these assessments. The facility has been modeled to demonstrate compliance with all applicable NAAQS, which are, in part, based on acceptable levels of environmental impact. Review of Appendix C indicates that the highest predicted impacts are well below the screening concentrations.

Growth Analysis (Demographics)

The growth analysis is a projection of the commercial, industrial, residential and other growth that may be projected to occur in the area as a result of the construction and operation of the proposed source. The anticipated increase in industrial, commercial, or residential growth in the area as a direct result of the proposed project will be negligible. Construction of the new power block at the existing Effingham will require a temporary construction work force for approximately 24 months. As a result there will be an increase of vehicular traffic on the paved plant access road due to the movement of commute and construction vehicles. Operation of the facility is expected to require less than five additional workers. No significant amount of related industrial growth is expected to accompany the operation of proposed power block. Since no significant associated commercial or industrial growth is projected as a result of the proposed action, negligible growth-related air pollution impacts are expected.

Class II Area Visibility Analysis

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

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

Georgia's SIP and Georgia *Rules for Air Quality Control* provide no specific prohibitions against visibility impairment other than regulations limiting source opacity and protecting visibility at federally protected Class I areas. To otherwise demonstrate that visibility impairment will not result from continued operation of the plant, the VISCREEN model was used to assess potential impacts on ambient visibility at so-called "sensitive receptors" within the SIA of Effingham. Since there is no ambient visibility protection standard for Class II areas, this analysis is presented for informational purposes only and predicted impacts in excess of screening criteria are not considered "adverse impacts" nor cause further refined analyses to be conducted.

The primary variables that affect whether a plume is visible or not at a certain location are (1) quantity of emissions, (2) types of emissions, (3) relative location of source and observer, and (4) the background visibility range. For this exhaust plume visibility analysis, a Level-1 visibility analysis was performed using the latest version of the EPA VISCREEN model according to the guidelines published in the *Workbook for Plume Visual Impact Screening and Analysis* (EPA-450/4-88-015). The VISCREEN model is designed specifically to determine whether a plume from a facility may be visible from a given vantage point. VISCREEN performs visibility calculations for two assumed plume- viewing backgrounds (horizon sky and a dark terrain object). The model assumes that the terrain object is perfectly black and located adjacent to the plume on the side of the centerline opposite the observer.

In the visibility analysis, the total project NO_X and PM_{10} emissions increases were modeled using the VISCREEN plume visibility model to determine the impacts. For both views inside and outside the Class II area, calculations are performed by the model for the two assumed plume-viewing backgrounds. The VISCREEN model output shows separate tables for inside and outside the Class II area. Each table contains several variables: theta, azi, distance, alpha, critical and actual plume delta E, and critical and actual plume contrast. These variables are defined as:

1. *Theta* – Scattering angle (the angle between direction solar radiation and the line of sight). If the observer is looking directly at the sun, theta equals zero degrees. If the observer is looking away from the sun, theta equals 180 degrees.

2. *Azi* – The azimuthal angle between the line connecting the observer and the line of sight.

3. *Alpha* – The vertical angle between the line of sight and the plume centerline.

4. *delta E* – Used to characterize the perceptibility of a plume on the basis of the color difference between the plume and a viewing background. A delta E of less than 2.0 signifies that the plume is not perceptible.

5. *Contrast* – The contrast at a given wavelength of two colored objects such as plume/sky or plume/terrain.

The analysis is generally considered satisfactory if *delta E* and *Contrast* are less than critical values of 2.0 and 0.05, respectively, both of which are Class I, not Class II, area thresholds. The Division has reviewed the VISCREEN results presented in the permit application and have determined that the visual impact criteria (*delta E* and *Contrast*) at the affected sensitive receptors are not exceeded as a result of the proposed project. Since the project passes the Level-1 analysis for a Class I area for the Class II area of interest, no further analysis of exhaust plume visibility is required as part of this air quality analysis.

As previously stated, the impact on Class II visibility analysis, GA EPD considers this requirement to apply to only those criteria pollutants with deterministic NAAQS (those which are assessed in accordance with the Draft 1990 New Source Review Workshop Manual modeling guidance). Thus, 24-hr $PM_{2.5}$ and the 1-hr NO_2 NAAQS do not apply to this assessment.

Georgia Toxic Air Pollutant Modeling Analysis

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

Selection of Toxic Air Pollutants for Modeling

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

As indicated in the Modeling memorandum included in Appendix C, Effingham discharges to the atmosphere twenty five hazardous air pollutants (HAPs) emitted from the combustion turbines and the duct burners through the stacks. Emission rates were estimated using AP-42 emission factors at the operating conditions that yield the worst emission rates.

Similar to the significant impact analysis, different operating conditions of the combustion turbines can result in different impacts on ambient air from the HAPs emissions. Therefore the results from the AERMOD runs for the load analysis previously conducted in the significance assessment were used to estimate the impact of the toxics pollutants.

Predicted concentrations (Modeled Ground Level Concentrations or MGLCs) were thus calculated for each HAP by multiplying the worst hypothetical predicted concentration obtained at the load analysis by the ratio of the emission rates (the generic emission rate of the load analysis and the toxic pollutant's emission rate).

Modeled concentrations were calculated for 1 year, 24 hours, and 1 hour averaging periods. The 1-hour results were converted to 15 minutes averages for further comparison with the corresponding Acceptable Ambient Concentration (AAC). The annual and 24-hour modeled values were compared directly to their corresponding AAC, which were calculated for each one of those substances and their applicable time-averaging periods according to EPD's Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions. Comparison shows that all MGLCs assessed were found to be less than their respective AACs, as presented in Table VII of the modeling memorandum. The air toxics analysis is discussed in Section 6.0 and presented in Table 6-12 of Application 19810.

For each TAP identified for further analysis, both the short-term and long-term AAC were calculated following the procedures given in Georgia EPD's *Guideline*. Figure 8-3 of Georgia EPD's *Guideline* contains a flow chart of the process for determining long-term and short-term ambient thresholds. Effingham referenced the resources previously detailed to determine the long-term (i.e., annual average) and short-term AAC (i.e., 24-hour or 15-minute). The AACs were verified by the EPD.

Determination of Toxic Air Pollutant Impact

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

Initial Screening Analysis Technique

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

9.0 EXPLANATION OF DRAFT PERMIT CONDITIONS

The permit requirements for this proposed facility are included in draft Permit Amendment No. 4911-103-0012-V-04-1.

Section 1.0: Facility Description

Section 1.3 was added to describe the proposed modification.

Section 2.0: Requirements Pertaining to the Entire Facility

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

Section 3.0: Requirements for Emission Units

Table 3.1.1 was added to include the newly proposed equipment.

Conditions 3.3.11 and 3.3.12 specify the requirements of 40 CFR 52.21(r) for this project.

Condition 3.3.13 specifies the applicable components of the Acid Rain Program.

Condition 3.3.14 specifies 40 CFR 60 Subpart KKKK as an applicable requirement for the combustion turbines and duct burners that are part of Application No. 19810.

Condition 3.3.15 specifies 40 CFR 60 Subpart Dc as an applicable requirement for the auxiliary boiler (emission unit ID No. AB2).

Condition 3.3.16 defines the common stacks for the combustion turbines and duct burners.

Condition 3.3.17 provides the definitions of startup and shutdown.

Condition 3.3.18 specifies the hours of operation limit associated with startup and shutdown of each combustion turbine (emission unit ID Nos. CTG3 and CTG4).

Condition 3.3.19 specifies the hours of operation limit associated with firing each combustion turbine (emission unit ID Nos. CTG3 and CTG4) on fuel oil.

Condition 3.3.20 specifies the hours of operation limit associated with the operation of each duct burner (emission unit ID Nos. DB3 and DB4).

Condition 3.3.21 specifies the hours of operation limit associated with the operation of the auxiliary boiler (emission unit ID No. AB2).

Conditions 3.3.22 through 3.3.25 specify the equipment design and end-of-pipe control components that constitute BACT for NOx, CO, and VOC emissions.

Constitute 3.3.26 specifies the annual NOx and CO emissions from the combined exhaust of each combustion turbine and its paired duct burner (emission unit ID Nos. CTG3/DB3 and CTG4/DB4) for all periods of operation.

Conditions 3.3.27 through 3.3.31 specifies the annual GHG emission limit (expressed as CO_{2e}) from each applicable combustion unit comprising this project.

Condition 3.3.32 specifies the SO_2 emissions limit, respectively, per 40 CFR 60 Subpart KKKK.

Condition 3.3.33 specifies the fuel sulfur content of fuels combusted in turbines with emission unit ID No. CTG3 and CTG4.

Condition 3.3.34 specify the fuel sulfur content of natural gas to be burned in the duct burners (emission unit ID Nos. DB3 and DB4), auxiliary boiler (emission unit ID No. AB2), and fuel gas heater (emission unit ID No. FP2).

Condition 3.3.35 specifies the short-term (3-hour average) BACT emission limits for NOx, CO, and VOC from the combined combustion turbine and duct burner stacks (emission unit ID Nos. CTG3/DB3 and CTG4/DB4), excluding periods of startup and shutdown, while firing natural gas.

Condition 3.3.36 specifies the short-term (3-hour average) BACT emission limits for NOx, CO, VOC, PM, PM10, and PM2.5 from the combined combustion turbine and duct burner stacks (emission unit ID Nos. CTG3/DB3 and CTG4/DB4).

Condition 3.3.37 specifies the opacity limit for all combustion equipment that comprises this project.

Conditions 3.3.38 and 3.3.39 specifies the short-term (3-hour average) BACT emission limits for NOx and CO emissions from the boiler with emission unit ID No. AB2.

Condition 3.3.40 specifies BACT for the cooling towers with emission unit ID Nos. CT3 and CT4.

Condition 3.3.41 specifies BACT for operation of the proposed fuel oil storage tank (emission unit ID No. T01).

<u>Requirements for Testing</u>

Condition 4.1.4 is added to specify the methods for the determination of compliance with the emission limits in Section 3 as they pertain to the project defined in Application No. 19810.

Condition 4.2.1 specifies the initial performance tests for each “affected facility” combusting natural gas. The term “affected facility” is defined as each combined cycle combustion turbine and duct burner system with emission unit ID Nos. CTG3/DB3 and CTG4/DB4.

Condition 4.2.2 specifies the initial performance tests for each “affected facility” combusting fuel oil. The term “affected facility” is defined as each combined cycle combustion turbine and duct burner system with emission unit ID Nos. CTG3/DB3 and CTG4/DB4.

Conditions 4.2.3 and 4.2.4 specify the annual performance test requirements for SO_2 emissions in accordance with 40 CFR 60.4415.

Condition 4.2.5 requires all CEMS and continuous monitoring systems and all required control technologies to be installed and operating during all performance testing required by Conditions 4.2.1 through 4.2.4.

Requirements for Monitoring (Related to Data Collection)

Condition 5.2.8a requires the installation and operation of a NOx CEMS that meets all applicable requirements of 40 CFR 60 Subparts A and KKKK and 40 CFR Part 75.

Condition 5.2.8b requires the installation and operation of a CO CEMS that meets all applicable requirements of 40 CFR Part 60.

Condition 5.2.9 requires the installation and operation of various continuous monitoring systems to aid in verifying compliance with the operational limits and in the computation of actual CO_{2e} emissions.

Conditions 5.2.10 and 5.2.11 specify details of the quality assurance of the CO CEMS required by Condition 5.2.8b.

Conditions 5.2.12 and 5.2.13 specify the requirements of CAM (40 CFR 64).

General Record Keeping and Reporting Requirements
New Condition 6.1.8 has been added which defines excess emissions, exceedances, and excursions for the purposes of the report required by Condition 6.1.4 as it relates to the project specified in Application No. 19810.

Specific Record Keeping and Reporting Requirements
Condition 6.2.15 specifies the monitoring requirement for natural gas sulfur content to verify compliance with Conditions 3.3.33a and 3.3.34.

Condition 6.2.16 specifies the monitoring requirements for fuel oil sulfur content to verify compliance with Condition 3.3.33b.

Condition 6.2.17 specifies the record keeping requirements for fuel usage data and this data is to be used to compute GHG emissions (expressed as CO_{2e}) to verify compliance with Conditions 3.3.27 through 3.3.31.

Condition 6.2.18 specifies the record keeping requirements per 40 CFR 60.4345(e) [NSPS KKKK].

Condition 6.2.19 specifies record keeping requirements as they relate to startup and shutdown in order to verify compliance with Condition 3.3.17.

Conditions 6.2.20 through 6.2.22 specify the record keeping requirements for operational time to verify compliance with Conditions 3.3.18 through 3.3.21.

Condition 6.2.23 specifies the record keeping requirements for purposes of Condition 6.1.8a.i and 6.1.8a.ii.

Conditions 6.2.24 through 6.2.26 specify the record keeping requirements to compute the NOx emissions from each combustion turbine and its paired duct burner (emission unit ID Nos. CTG3/DB3 and CTG4/DB4) in order to verify compliance with Conditions 3.3.26a and 3.3.26b.

Conditions 6.2.27 through 6.2.29 specify the record keeping requirements to compute the CO emissions from each combustion turbine and its paired duct burner (emission unit ID Nos. CTG3/DB3 and CTG4/DB4) in order to verify compliance with Conditions 3.3.26c and 3.3.26d.

Conditions 6.2.30 through 6.2.31 specify the record keeping requirements to compute the GHG emissions (expressed as CO_{2e}) from the applicable equipment in order to verify compliance with Conditions 3.3.27 through 3.3.31.

Condition 6.2.32 specifies the record keeping requirement to verify compliance with Condition 3.3.40.

Condition 6.2.33 specifies initial reporting requirements for the project.

Condition 6.2.34 specifies quarterly reporting requirements for the project.

Condition 6.2.35 specifies record keeping and reporting requirements to verify compliance with Condition 3.3.33 and 3.3.34.