Prevention of Significant Air Quality Deterioration Review

Preliminary Determination

February 12, 2010

Facility Name: Live Oaks Power Plant
City: Sterling
County: Glynn
AIRS Number: 04-13-127-00075
Application Number: 18569
Date Application Received: November 19, 2008

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

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SUMMARY

The Environmental Protection Division (EPD) has reviewed the application submitted by Live Oaks Company, LLC for a permit to construct and operate a combustion turbine combined-cycle power plant. The proposed project will be located in Sterling, Georgia, and will generate approximately 600 megawatts (MW) of power. The single power block will be fired exclusively with natural gas, and will consist of two combustion turbines, each with a nominal power output of 200 MW; two heat recovery steam generators (HRSGs) with supplemental firing; and one steam turbine with a nominal output of 200 MW. Additional equipment includes a 600 kW emergency generator, a 310 hp emergency firewater pump, two fuel heaters, and a 10-cell mechanical draft cooling tower.

The proposed construction of this project will result in emissions of air pollutants from the facility. The sources of these emissions include the combustion turbines, duct burners, fuel heaters, emergency generator, emergency firewater pump, and cooling tower.

The construction of the Live Oaks Power Plant will result in emissions of SO_2, PM, PM_{10}, $PM_{2.5}$, NO_X, CO, VOC, and Sulfuric Acid Mist (H_2SO_4). PM_{10} will be used as a surrogate to estimate emissions of $PM_{2.5}$ throughout this analysis per EPA policy. Please see section 3.2 for more information. A Prevention of Significant Deterioration (PSD) analysis was performed for the facility for all pollutants to determine if any increase was above the "significance" level. The emissions of PM, PM_{10}, $PM_{2.5}$, NO_2, CO, and VOC are all above the PSD significance levels.

The Live Oaks Power Plant is located in Glynn County, which is classified as "attainment" or "unclassifiable" for SO_2, $PM_{2.5}$ and PM_{10}, NO_X, CO, and ozone.

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

It is the preliminary determination of the EPD that the proposal provides for the application of Best Available Control Technology (BACT) for the control of PM, PM_{10}, $PM_{2.5}$, NO_2, CO, and VOC, as required by federal PSD regulation 40 CFR 52.21(j).

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

In December of 2001, Live Oaks Company, LLC submitted an application for a permit to construct and operate a very similar combined cycle facility at this location. The PSD permit for this facility was final in February of 2004. In October of 2007 the construction deadline was extended to August 2008, but construction never commenced. Subsequently in November of 2008, Live Oaks Company, LLC submitted a new application for an updated facility which this preliminary determination addresses. Because of the design and operational changes in the new application, and rule changes since the earlier application submittal, there are several differences between the earlier permit and preliminary determination, and the new ones.

This Preliminary Determination concludes that an Air Quality Permit should be issued to Live Oaks Power Plant for the construction necessary to build the combined-cycle power plant. Various conditions have been incorporated into the new SIP construction permit to ensure and confirm compliance with all applicable air quality regulations. A copy of the draft permit is included in Appendix A.

1.0 INTRODUCTION – FACILITY INFORMATION AND EMISSIONS DATA

On November 19, 2008, Live Oaks Company, LLC (hereafter Live Oaks Power Plant) submitted an application for an air quality permit to construct and operate a combined-cycle power plant. The facility will be located at Green Swamp Road in Sterling, Glynn County. Once operational, the facility will be a Title V Major Source for the pollutants indicated in Table 1-1.

Table 1-1: Title V Major Source Status

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

Table 1-2 below lists all past 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. Both of these permits have expired because construction was not started within the time allowed by the PSD rules.

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

Permit Number and/or Off-Permit Change	Date of Issuance/ Effectiveness	Purpose of Issuance
4911-127-0075-P-01-0	02-04-2004	Initial Construction Permit
4911-127-0075-P-01-1	10-24-2007	Extend Construction Start Deadline to Aug 4, 2008

Based on the proposed project description and data provided in the permit application, the estimated emissions of regulated pollutants from the facility are listed in Table 1-3 below:

Table 1-3: Emissions from the Project

Pollutant	Potential Emissions (tpy)	PSD Significant Emission Rate (tpy)	Subject to PSD Review
PM	76.0	25	Yes
PM_{10}	74.3	15	Yes
VOC	132.5	40	Yes
NO_X	185.1	40	Yes
CO	418.5	100	Yes
SO_2	32.9*	40	No
TRS	n/a	10	No
Pb	n/a	0.6	No
Fluorides	n/a	3	No
H_2S	n/a	10	No
SAM	6.8*	7	No

*assumes 0.8 grains sulfur/100 scf in pipeline natural gas gas.

2.0 PROCESS DESCRIPTION

In application No. 18569, received on November 19, 2008, Live Oaks Company, LLC proposes to construct and operate a natural gas fired cogeneration facility at a site to be called the Live Oaks Power Plant in Sterling, Georgia (Glynn County). The facility will utilize one train of combined cycle generating units to generate electric power and steam.

The proposed facility will operate as a fully dispatchable electric generating facility, and can be expected to operate up to a maximum of 24 hours per day, 365 days per year. The combined cycle system will utilize two combustion turbines and one steam turbine, configured in a two-on-one arrangement. The heat content of the exhaust gasses will be recovered by a heat recovery steam generator (HRSG), and used to drive a steam turbine. During peak loads a duct burner in the HRSG can be fired to add additional heat energy to the gas turbine exhaust, increasing the production of steam sent to the steam turbine. For permitting purposes, the duct burners are assumed to operate for 4,000 hours per year. The combustion turbines (CTs) selected are Siemens model SGT6-5000F. Each Combustion Turbine will generate 200 MW of electric power. The Gross Electrical Capacity of the combined cycle facility firing natural gas will then be 600 MW. The CTs will be capable of continuous operation for up to 8760 hr/yr and will typically operate between 70 and 100 percent of load, with the economic incentive to dispatch the plant to as near to 100-percent load whenever possible.

The hourly electrical production rate is dependent on operating and ambient conditions such as CT operation load, represented by the percent of maximum load, and ambient temperature. The production rates are based on the maximum output of the turbine at the ambient conditions. An evaporative cooling system will be used to enhance the power output of the combustion turbine generators during the summer months of operations.

The facility will fire pipeline quality natural gas exclusively. Emissions of SO_2 and sulfuric acid mist (SAM) will be minimized by restricting fuel used to pipeline natural gas only. The use of clean, low-ash fuels and efficient combustion will limit the emissions of PM, PM_{10}, PM2.5, and trace metals.

A fuel gas heater will be operated in conjunction with the combustion turbines. The purpose of this heater is to preheat the natural gas prior to its introduction into the combustion turbines in order to provide the optimum combustion efficiency. The fuel gas heater is rated at 10 MMBtu/hr.

A mechanical draft cooling tower comprising 10 cells will be provided for the combined cycle units. The cooling tower will be used to provide cool water to the condensing steam turbine. The tower will be a mechanical draft counter-flow design, and will be equipped with high-efficiency drift eliminators that use inertial separation caused by airflow direction changes to remove water droplets from the air stream exhausting from the cooling tower.

Auxiliary equipment will include a 310 hp diesel firewater pump and a 600 kW emergency generator at the facility.

The Live Oaks Power Plant permit application and supporting documentation are included in Appendix A of this Preliminary Determination and can be found online at www.georgiaair.org.

3.0 REVIEW OF APPLICABLE RULES AND REGULATIONS

3.1 State Rules

The Georgia Rule for Air Quality Control (Georgia Rule) 391-3-1-.03(1) requires that any person prior to beginning the construction or modification of any facility which may result in an increase in air pollution shall obtain a permit for the construction or modification of such facility from the Director upon a determination by the Director that the facility can reasonably be expected to comply with all the provisions of the Act and the rules and regulations promulgated there under. Georgia Rule 391-3-1-.03(8)(b) continues, stating 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 Rules 391-3-1-.02(2)(b), (d), and (g) limit visible emissions, PM emissions, and fuel sulfur content respectively. Georgia Rule (b) limits visible emissions to not equal or exceed forty (40) percent from the combined CT/HRSG stack, diesel firewater pump and emergency diesel generator.

There is no applicable state regulation that limits PM emissions from the combustion turbine portion of the CT/HRSG system. Georgia Rule (d) limits PM emissions from the duct burner since it supplies indirect heat to the water in the HRSG heat exchanger. This superheated stream (turbine exhaust and duct burner heat energy) is blown through a heat exchanger, which raises the temperature of water to superheated steam for use in the steam generator. The duct burner has a maximum heat input of 359 MMBtu/hr; at that rate, the Georgia Rule (d) allowable PM emission rate is 0.1 lb/MMBtu, or 35.9 lb/hour. Georgia Rule (d) also applies to the fuel gas heater. The heater has a maximum heat input of 10 MMBtu/hr; at that rate, the Georgia Rule (d) allowable PM emissions rate is 0.7 lb/MMBtu while firing natural gas. The maximum anticipated PM emission rate is 0.007 lb/MMBtu, which is well below the Georgia Rule (d) limit.

Georgia Rule (g) limits the fuel sulfur content of the fuels consumed in the turbines and duct burners to not equal or exceed 3.0 weight percent. For the fuel gas heater, diesel firewater pump and emergency generator the fuel sulfur content of the fuels consumed is not to equal or exceed 2.5 weight percent. Live Oaks based the potential SO_2 emissions on a natural gas sulfur limit of 0.8 grains per 100 standard cubic feet of natural gas and low sulfur diesel fuel at 0.05% sulfur by weight, leaving them well within the sulfur limits in Georgia Rule (g).

Compliance with all applicable state rules is therefore expected. As discussed in Section 4.0, the PSD BACT limits are all at least as stringent as, and in most cases are significantly more stringent than, the state rules.

3.2 Federal Rule - PSD

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

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

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

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

Definition of BACT

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

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

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

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

$PM_{2.5}$ Surrogate

On May 8, 2008, EPA issued a rule that finalizes several NSR program requirements for sources that emit $PM_{2.5}$ and other pollutants that contribute to $PM_{2.5}$. The rule adopts a significant emission rate of 10 tons per year for direct $PM_{2.5}$ emissions as well as other levels for pollutants that contribute to $PM_{2.5}$ (including SO_2 , NO_x, and VOC). However, the new rule contains a transition policy that suggests SIP-approved states may continue to use PM_{10} as a surrogate for $PM_{2.5}$ in attainment areas until the state revises its SIP. The surrogate policy was initially stated in "Interim Implementation for the New Source Review Requirement for $PM_{2.5}$" (Seitz Memorandum), October 23, 1997. Therefore, since Live Oaks Power Plant is located in an attainment area for $PM_{2.5}$ (Glynn County), the new rule does not apply until Georgia revises its SIP.

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

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

Section 3.1 (Stationary Gas Turbines) contains PM emission factors but does not specify a particle size for these emissions.

Section 1.4 (Natural Gas Combustion) contains PM emission factors and notes that it is assumed all PM is less than 1.0 micrometer in diameter.

Based on a review of the RBLC for $PM_{2.5,}$ only one large combustion turbine project is listed. The Cass County Power Plant (RBLC Listing No. NE-0021) in Nebraska lists a $PM_{2.5}$ limit of 0.1200 MMBtu/hr and 15.3 lbs per hour. However, after speaking with the permitting authority, it was confirmed that this listing is in error and is actually a limit for PM_{10} emissions rather than $PM_{2.5}$ emissions. Thus there are no RBLC entries for combustion turbines establishing a permit limit for $PM_{2.5}$ emissions.

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

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

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

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

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

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

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

3.3 Federal Rule – NSPS Subpart Dc

40 CFR 60, Subpart Dc – Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units for Which Construction is Commenced After June 9, 1989 that has a maximum capacity of 100 MMBtu/hr or less, but greater than or equal to 10 MMBtu/hr

Applicability: NSPS Dc is an applicable requirement for the natural gas fuel heaters because they have a heat input rating that is greater than or equal to 10 MMBtu/hr but less than 100 MMBtu/hr and will be constructed after June 9, 1989.

Emission Standard: NSPS Dc does not define any emission standard for the fuel heaters because they are exclusively fired with natural gas.

Compliance Demonstration: The Permittee is subject to the reporting and record keeping requirement of 40 CFR 60.48c(g)2. This portion of NSPS Dc requires keeping records of the amount of fuel combusted monthly.

3.4 Federal Rule – NSPS Subpart KKKK

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 10.7 gigajoules (10 MMBtu) per hour, 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 Subparts Da, Db, and Dc of this part.

Emission Standard: 15 ppmvd of NO_X corrected to 15 percent O_2 or 54 ng/J of useful output (0.43 lb/MWh) This emission standard applies to emissions from the combustion turbine, as well as any additional emissions from the inline HRSG/duct burner.

From the combustion turbine, no gases which contain SO_2 in excess of 110 nanograms per Joule (ng/J) (0.90 pounds per megawatt-hour (lb/MWh)) gross output shall be emitted, OR the facility must not burn in the subject stationary combustion turbine any fuel which contains total potential sulfur emissions in excess of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input.

Compliance Demonstration: The Permittee may install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for NO_X as described in 40 CFR 60.4335(b) and 40 CFR 60.4345 to demonstrate continuous compliance with the NO_X emission standard. To demonstrate compliance with the SO_2 limits the Permittee may monitor fuel sulfur content by providing the fuel quality characteristics in a valid purchase contract, tariff sheet, or transportation contract demonstrating that the fuel has potential sulfur emissions of less than 0.060 lb SO_2/MMBtu. Additionally, performance tests for compliance with the NO_X and SO_2 limits must be performed on an annual basis, with each test carried out no more than 14 months following the previous performance test. Excess emissions are defined as when the 30-day rolling average emission rate of NO_X exceeds the allowable emission rate as measured by the CEMS.

3.5 Federal Rule – NSPS Subpart IIII

40 CFR 60, Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

Applicability: NSPS Subpart IIII is an applicable requirement for the emergency firewater pump and the emergency generator because the facility will own and operate these engines, and both will commence construction after July 11, 2005.

Emission Standard: For the 310 HP firewater pump, the emission limits are 3.0 g/HP-hr of NO_X+NMHC [1], and 0.15 g/HP-hr of PM. If the rated speed is greater than 2650 rpms [2], then the limits are 7.8, 2.6, and 0.40 g/HP-hr of NO_X+NMHC, CO, and PM respectively, as stated in 40 CFR Part 60 Subpart IIII, Table 4.

For the 600KW emergency generator, the emission limits are 6.4, 3.5, and 0.2 g/kW-hr of NMHC+NO_X, CO, and PM respectively, as stated in Table 1 of 40 CFR 89.112.

Compliance Demonstration: To demonstrate compliance the Permittee must operate and maintain the stationary CI internal combustion engine and control device (if any) according to the manufacturer's written instructions or procedures developed by the owner or operator that are approved by the engine manufacturer. In addition, owners and operators may only change those settings that are permitted by the manufacturer.

3.6 Federal Rules - National Emissions Standards For Hazardous Air Pollutants

HAPs from combustion equipment are primarily the result of incomplete combustion. Low CO is an indication of very good combustion and therefore HAP emissions should also be low. According to EPA, the following HAPs have been measured above the emission test method detection limits from gas-fired combustion turbines: acetaldehyde, acrolein, benzene, ethyl benzene, formaldehyde, naphthalene, PAH, toluene, and xylene. The concentrations of these HAPs are low with many concentrations being very close to the emission test method detection limits. EPA has developed and is maintaining the Stationary Combustion Turbines Emissions Database. After review of this database, EPD does not believe that the proposed site is a major source for HAPS under 40 CFR Part 63.

EPD has determined that, based on testing results from other similar facilities, these plants are not major sources for HAPs; therefore EPD will not require Live Oaks to conduct stack tests to confirm that Formaldehyde, Acetaldehyde, and Toluene are below acceptable levels of 10 tpy for individual HAPs or 25 tpy for total HAPs emitted.

If the turbines on site did have potential to emit above 10 tpy of an individual HAP, or 25 tpy of total HAPs, the source could be Subject to 40 CFR 63 Subpart YYYY. EPA promulgated this new MACT standard for new stationary combustion turbines on March 5, 2004. These standards

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[1] NMHC – Non Methane Hydrocarbons

[2] rpm – revolutions per minute

apply to stationary combustion turbines on which construction commenced after January 14, 2003. On April 7, 2004, however, EPA proposed to remove gas-fired units from the CT source category regulated by Subpart YYYY. In the interim, the Agency has stayed the applicability of Subpart YYYY requirements for gas only fired CTs. The combustion turbines at Live Oaks Power Plant will burn natural gas only, and consequently would not be subject to Subpart YYYY, at this time, even if the facility were major for HAPS.

3.7 State and Federal – Startup and Shutdown and Excess Emissions

Excess emission provisions for startup, shutdown, and malfunction are provided in Georgia Rule 391-3-1-.02(2)(a)7 (NSPS emission standards are not covered by these provisions). Excess emissions from the combined turbine/duct burner stack most likely will occur during startup and shutdown because the combined unit exhaust will bypass the SCR. The SCR will be bypassed during those periods of operation when the temperature of the turbine/duct burner combined exhaust is not conducive to proper operation of the SCR.

EPA's general policy regarding excess emissions also states, "Startup and shutdown of process equipment are part of the normal operation of a source and should be accounted for in the design and implementation or the operation procedure for the process and control equipment. Accordingly, it is reasonable to expect that careful planning will eliminate violations of emission limitations during such periods." EPA Region 4 recognizes that with combustion turbines, emissions of some pollutants may be higher during startup and shutdown than during steady state operation. Therefore, the emission limits appropriate for steady state operation may not be achievable during periods of startup and shutdown. This does not mean, however, that BACT requirements do not apply during startup and shutdown. Rather, BACT requirements for startup and shutdown of combustion turbines are tailored to the characteristics of the specific system. EPA requires that air permits for such facilities include (1) definitions of startup and shutdown and (2) a mechanism to limit emissions from startup and shutdown. The Division recognizes that emissions of some pollutants may be higher during startup and shutdown than during normal operation. With this in mind, the Division will include permit language (1) that defines startup and shutdown; (2) that defines a BACT emissions limit in tons per year which would include startup and shutdown; and (3) that states that excess emissions provisions in Georgia Rule 391-3-1-.02(2)(a)7 apply to the short term BACT limits which generally allow excess emissions caused by startup and shutdown. In particular, the Division will include language in the annual NO_X and CO limits that specifies emissions during startup and shutdown contribute to these emissions limits.

Turbine startup is defined as the period of time from initiation of combustion turbine firing until the unit reaches steady state load operation. Steady state operation shall be reached when the combustion turbine reaches minimum load (50%) and the steam turbine is declared available for load changes.

Cold Start – Occurs when the combined-cycle unit is started up after having been shut down for 72 hours or more. The total time for this startup condition is 215 minutes. The first CT is started and held at certain levels of heat input while the exhaust gases from the CT heat up the HRSG and produce steam for the steam turbine. The steam turbine load is applied first, with the first combustion turbine load applied next. Then the second combustions turbine is started with its load applied last. At 215 minutes, both CTs and the steam turbine reach full load for the specific conditions.

Warm Start - Occurs when the combined-cycle unit has been shut down for less than 72 hours, and more than 8 hours. The total time for this startup condition is 125 minutes (about 2 hours). The first CT is started and held at certain levels of heat input while the exhaust gases from the CT heat up the HRSG and produce steam for the steam turbine. The steam turbine load is applied first, with the first combustion turbine load applied next. Then the second combustion turbine is started with its load applied last. At 125 minutes, both CTs and the steam turbine reach full load for the specific conditions.

Hot Start - Occurs when the combined-cycle unit has been shut down for less than 8 hours. The total time for this startup condition is 65 minutes. During a hot start, either both CTs, or one CT, can be initially started. As noted above, most startup conditions would involve the initial start of one turbine. As the temperature in the SCR is increased, the ammonia system would be activated to reduce NO_X emissions to the BACT emissions limit.

Shutdown – is defined as the period of time from steady state operation to cessation of combustion turbine firing. This period may not exceed 60 minutes for a planned shutdown.

3.8 Federal Rule – 40 CFR 64 – Compliance Assurance Monitoring

Under 40 CFR 64, the *Compliance Assurance Monitoring* Regulations (CAM), facilities are required to prepare and submit monitoring plans for certain emission units along with the Title V application. The CAM Plan provides an on-going and reasonable assurance of compliance with emission limits. Under the general applicability criteria, this regulation applies to units that use a control device to achieve compliance with an emission limit and whose pre-controlled emissions levels exceed the major source thresholds under the Title V permitting program. Because at least one Live Oaks pre-controlled emissions level exceeds its Title V major source threshold, and they will employ air pollution control devices to meet that emission limit, they are subject to CAM. Live Oaks Power Plant will therefore be required to submit a CAM plan with their Title V application which must be submitted within 1 year after the facility commences operation.

3.9 Federal Rules – Acid Rain Program

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

This applicability requires the facility to do the following:

- Submit the Phase II Acid Rain Permit (ARP) to include the two new combustion turbines (Source Codes CT1, and CT2);
- Demonstrate compliance with the ARP provisions, meeting the requirements specified in 40 CFR 75; and
- Hold allowances equivalent to annual SO_2 emissions. (The combustion turbines (Source Codes CT1, and CT2) are not subject to the NO_X requirements in 40 CFR 76.)

The facility must submit an Acid Rain permit application that includes the date that the units will commence commercial operation and the deadline for monitoring certification (90 days after commencement of commercial operation). Acid Rain permits for new units are due 24 months before the unit commences operation.

A Title IV Acid Rain monitoring plan must be developed by the facility as required under 40 CFR 72. The plan must include the installation, proper operation, and maintenance of continuous monitoring systems or approved monitoring provisions under 40 CFR 75 for SO_2 and CO_2 (as a diluent). Depending on the monitoring technology available at the time of installation, the plan must cite the specific operating practices and maintenance programs that will be applied to the instruments. The plan must also cite the specific form of records that will be maintained, their availability for inspection and the length of time that they will be archived. The plan must further cite that the Acid Rain permit and applicable regulations will be reviewed at specific intervals for continued compliance and must cite specific mechanisms to be used to keep current on rule applicability.

3.10 Federal Rules – Clean Air Interstate Rule (CAIR)

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

The Clean Air Interstate Rule regulations apply to the proposed combined-cycle electric generating units because they each have a nameplate capacity greater than 25 MW, they are fossil-fuel fired, and they are to supply electricity for sale, whether wholesale or retail.

These regulations established the model rule comprising general provisions and the designated representative, permitting, allowance, monitoring, and opt-in provisions for the State Clean Air Interstate Rule (CAIR) NO_X, and SO_2 Trading Programs, under section 110 of the Clean Air Act and §51.124 of Chapter I, as a means of mitigating interstate transport of fine particulates, NO_X and sulfur dioxide. The owner or operator of a unit or a source was to comply with the requirements of these regulations as a matter of federal law only if the State with jurisdiction over the unit and the source incorporates by reference such subparts or otherwise adopts the requirements of such subparts in accordance with §51.124(o)(1) or (20) of Chapter I, the State submits to the Administrator one or more revisions of the State implementation plan that include such adoption, and the Administrator approves such revisions.

The CAIR rule that was previously vacated by the U.S. Court of Appeals for the District of Columbia Circuit Court was reinstated on December 23, 2008. Therefore this regulation is applicable to the proposed combustion turbines (Source Codes CT1 and CT2) when they commence operation.

4.0 CONTROL TECHNOLOGY REVIEW

4.1 Combustion Turbine & Duct Burner

4.1.1 Nitrogen Oxides

Nitrogen Oxides (NO_X) are formed during the combustion of fuel and generally classified as thermal NO_X, prompt NO_X or fuel-related NO_X. Thermal NO_X results when atmospheric nitrogen is oxidized at high temperatures to yield NO, NO_2, and other oxides of nitrogen. Most thermal NO_X is formed in high temperature stochiometric flame pockets downstream of the fuel injectors where combustion air has mixed sufficiently with the fuel to produce a peak temperature and oxidize gaseous nitrogen present in the combustion air. Prompt NO_X forms within the combustion flame and is usually negligible when compared to the amount of thermal NO_X formed. Fuel-related NO_X is formed by the oxidation of the chemically bound nitrogen in the fuel.

Summary of Control Technologies

There are several technologies to consider for controlling NO_X emissions from combustion turbines in a combined cycle configuration. These are categorized into pre-combustion and post-combustion controls.

Pre-Combustion NO_X Control Technologies

Dry Low NO_X (DLN) Combustors
In the past several years, manufacturers have offered and installed combustion turbines with DLN combustors. These combustors, which are offered on conventional machines manufactured by General Electric (GE), Siemens Westinghouse and Mitsubishi Heavy Industries (MHI), can achieve NO_X concentrations of as low as 9 ppmvd or less when firing natural gas. All these vendors have offered DLN combustors on advanced heavy-duty industrial units. Thermal NO_X formation is inhibited by using combustion techniques where the natural gas and combustion air are premixed before ignition. For the combined-cycle units being considered for the project, the standard combustion chamber design includes the use of DLN combustor technology.

Post Combustion NO_X Control Technologies

Wet Injection
The injection of water or steam in the combustion zone of combustion turbines reduces the flame temperature with a corresponding decrease of NO_X emissions. The amount of NO_X reduction possible depends on the combustor design and the water-to-fuel ratio employed. An increase in the water-to-fuel ratio will cause a concomitant decrease in NO_X emissions until flame instability occurs. At this point, operation of the combustion turbine becomes inefficient and unreliable, and significant increases in products of incomplete combustion result (i.e., CO and VOC emissions). In modern applications, wet injection is used only for units firing fuel oil.

Selective Catalytic Reduction (SCR)
The basic principle of SCR is the reduction of NO_X to N_2 and H_2O by the reaction of NO_X and NH_3 within a catalyst bed. The primary reactions occurring in SCR require O_2, so that the catalyst performs more effectively at O_2 levels above 2 to 3 percent.

Several different catalysts are available for use at different exhaust gas temperatures. In use the longest and most common are base metal catalysts, which typically contain titanium and vanadium oxides, and which also may contain molybdenum, tungsten, and other elements. Base metal catalysts are useful between 450 and 800°F. For high temperature operation (675°F to over 1100°F), zeolite catalysts may be used. In clean, low temperature (350 to 550°F) applications, catalysts containing precious metals such as platinum and palladium are useful.[3]

The mechanical operation of an SCR system is quite simple. It consists of a reactor chamber with a catalyst bed, composed of catalyst modules, and an NH_3 handling and injection system, with the NH_3 injected into the flue gas upstream of the catalyst. There are no moving parts. Other than spent catalyst, the SCR process produces no waste products.

In principle, SCR can provide reductions in NO_X emissions approaching 100 percent. (Simple thermodynamic calculations indicate that a reduction of well over 99 percent is possible at 650°F.) In practice, commercial SCR systems have met control targets of over 90 percent in many cases.

SCR is very cost-effective for natural gas-fired units. Less catalyst is required since the waste gas stream has lower levels of NO_X, sulfur, and particulate matter. Combined-cycle natural gas turbines frequently use SCR technology for NO_X reduction. A typical combined-cycle SCR design places the reactor chamber after the superheater within a cavity of the HRSG system. The flue gas temperature in this area is within the operating range for base metal-type catalysts.[4] For natural gas-fired combined cycle gas turbine units, SCR is considered an available, demonstrated technology.

SCONOX^{TM} System

Goal Line Environmental Technologies (GLET) developed SCONOX, a relatively new post combustion technology, which utilizes a coated oxidation catalyst to oxidize and remove both NO_X and CO without a reagent such as NH_3. Now offered by EmeraChem (formerly Goal Line), the technology is marketed under the name EMx. EMx is described as the next generation of the SCONOX technology.

The EMx system consists of a platinum-based catalyst coated with potassium carbonate (K_2CO_3) to oxidize CO to CO_2 and NO to NO_X. CO_2 generated in the catalyst bed is exhausted to the atmosphere with the flue gas, while NO_2 absorbs onto the catalyst to form potassium nitrite (KNO_2) and potassium nitrate (KNO_3). Periodically, dilute hydrogen gas is passed across the catalyst to regenerate the potassium carbonate coating. The regeneration step converts KNO_2 and KNO_3 into K_2CO_3, water, and nitrogen gas. In order to maintain continuous operation during catalyst regeneration, the system is furnished in arrays of 5-module catalyst sections. During operation, 4 of the 5 modules are online and treating flue gas, while one module is isolated from the flue gas for regeneration. NO_X reduction in the system occurs in an operating temperature range of 300 to 700°F, and, therefore, must be installed in the appropriate temperature section of a HRSG.

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[3] Institute of Clean Air Companies, description of NOX control technologies.

[4] EPA's Air Pollution Control Technology Fact Sheet for SCR, EPA-452/F-03-032.

A regeneration cycle is typically set to last for 3 to 5 minutes. Regeneration gas is produced by reacting natural gas with O_2 present in ambient air. The EMx™ system uses a gas generator to produce hydrogen and carbon dioxide. For EMx™ systems installed in locations of the HRSG above 500°F, a separate regeneration gas generator is not required. Instead, regeneration gas is produced by introducing natural gas directly across the EMx catalyst that reforms the natural gas.

The EMx™ system catalyst is subject to reduced performance and deactivation due to exposure to sulfur oxides. For this reason, an additional catalytic oxidation/absorption system (SM_x™) to remove sulfur compounds is installed upstream of the EMx™ catalyst. The SO_2 is oxidized to sulfur trioxide (SO_3) by the SM_x™ catalyst. The SO_3 is then deposited on the catalyst and removed from the catalyst when it is regenerated. The SM_x™ catalyst is regenerated along with the EMx™ catalyst.

The EMx™ catalyst must be recoated, or "washed" every 6 months to 1 year. The frequency of washing is dependent on the sulfur content in the fuel and the effectiveness of the SM_x catalyst. The "washing" consists of removing the catalyst modules from the unit and placing each module in a potassium carbonate reagent tank, which is the active ingredient of the catalyst. The SM_x catalyst also requires washing.

EmeraChem states that their EMx technology (the second-generation of the EMx™ NO_X absorber technology) is capable of reducing gas-fired NO_X emissions to less than 1.0 ppm, releases undetectable levels of CO, reduces VOC emissions by greater than 90 percent, reduces fine particulate matter by 30 percent, and reduces sulfur emissions by 95-percent.

Commercial experience with the EMx™ control system is limited. The NO_X reduction system was commercially demonstrated first at the 32 MW (GE LM2500 turbine) Sunlaw Federal Cogeneration Facility located in Vernon, California. NO_X emissions from the process were less than 2 ppm during 100 percent of operation, and less than 1 ppm for 90 percent of operation. Other installations of the technology include a 15 MW (Solar Titan 130 turbines) installation at the University of California, San Diego, and a 45 MW (Alstom GTX100 turbine) installation at the City of Redding Municipal Electric Plant. A number of smaller installations are also operating – two 5 MW installations at the Wyeth BioPharma cogeneration facility, Andover, MA, and a 5 MW installation at the Montefiore Medical Center, Bronx, NY. Actual NO_X emissions from these smaller installations are typically below 1.5 ppm.

EmeraChem states that the process is scalable. Alstom Power, one of the EMx licensees, engineered and installed the technology on one of their GTX100 (43 MW class) gas turbines. This size and design is a reproducible module that would be replicated several times for larger installations. Alstom has already produced preliminary designs for several standard size plants that match standard sizes of larger turbines.

The number of permitted and operating EMx installations is growing and the future of the EMx technology is very promising. Despite the future promise, commercial experience to date with the EMx™ control system is limited to just 8 small units. Live Oaks Power Plant's combustion turbines are approximately 200 MW each and there is no experience of the EMx™ system on turbines of this size.

XONON™ Catalytic Combustor

The XONON™ Combustion System is a catalytic combustion system developed by Catalytica Energy Systems, Inc., that is designed to avoid high temperatures created in conventional combustors. The XONON™ combustor utilizes a catalyst integrated into the gas turbine combustor to limit temperature below the temperature where NO_X is formed. It also lowers CO and VOC emissions.

The XONON™ technology is installed as an integral part of the combustor. Conventional combustion fuel and air are supplied to a combustor; however, rather than combusting the fuel in a flame, the XONON™ system combusts the fuel using a catalyst at lower temperatures. Fuel and air are thoroughly mixed prior to entering a catalyst region that acts to combust the fuel, releasing its energy. The XONON™ catalyst module consists of a channel structure whereby the fuel-air mixture readily passes through the channels coated with the catalyst. As fuel and O_2 molecules contact the channel walls, the molecules and catalyst interact and are rearranged at temperatures well below those of flame combustion. Energy is extracted from the fuel in this manner, producing carbon dioxide and water byproducts. Nitrogen molecules are not involved in the XONON™ chemistry and pass through the channels unchanged, thereby preventing the formation of NO_X.

The XONON™ technology was first designed into the combustor of a 1.4 MW Kawasaki Model M1A-13A gas turbine at Silicon Valley Power in Santa Clara, California in 1999. Since its installation, the turbine has operated as a demonstration of XONON™'s performance. The California EPA's Air Resources Board evaluated NO_X and CO CEMS data and concluded that XONON™ achieved a NO_X level of 2.5 ppmvd at 15-percent O_2 and a CO level of 6.0 ppmvd at 15-percent O_2.

Other commercial installations of the XONON™ technology include a 1.5 MW Kawasaki MIA-13X installation at Sonoma Development Center in Eldridge, CA and a 1.4 MW Kawasaki GPB15X installation at Plains Exploration & Production Company in San Luis Obispo, CA. The Eldridge installations expected performance was 3 ppmvd NO_X and 10 ppmvd CO. According to the manufacturer, the unit has consistently achieved continuous NO_X emission levels below the emission target and on the average, NO_X emissions are under 2.0 ppmvd at 15-percent O_2. Based on manufacturer report, the unit at the Plains Exploration & Production Co. has achieved NO_X emissions around 0.8 ppmvd at 15 percent O_2 on the average.

After review of information from the California Air Resources Board (CARB) and EPA, the Division is unable to support setting BACT based on this emerging technology because it is not yet commercially available and therefore is not considered technically feasible. However, the Division will continue to monitor the availability and application of XONON™ and its impact on future natural gas fired turbine BACT.

NOXOUT® Process

The NOXOUT® Process is FUEL TECH's urea-based Selective Non-Catalytic Reduction process for reduction of oxides of nitrogen (NO_X) from stationary sources. The process requires precisely engineered injection of stabilized urea liquor into combustion flue gas whereby most NO_X reduction occurs in a temperature range between 1650ºF to 2100ºF. To achieve this in commercial practice, injection occurs between 1600ºF to 2500ºF, reflecting the wide variety of flue gas dynamics experienced in FUEL TECH's many varied installations. The injection is typically multi-level and controlled automatically with respect to load or duty changes. The process uses the enthalpy of the gas, rather than stationary bed catalyst as required by SCR, to drive the NO_X reduction action.

The NOXOUT® Process is being successfully applied commercially on coal, oil, and gas-fired boilers, biomass-fired boilers, process heaters, some types of cement kilns, various steel industry furnaces, FCC-CO boilers, and incinerators firing various waste materials. However, commercial application of the NOXOUT® system is limited and has not been demonstrated on any combustion turbine/HRSG unit.[5]

The NOXOUT® process is not technically feasible for the proposed project because of the high application temperature of 1,600°F to 1,950°F. The maximum exhaust gas temperature of the "F" Class CT is about 1,100°F. Raising the exhaust temperature the required amount essentially would result require installation of a heater. This would be economically prohibitive and would result in an increase in fuel consumption, an increase in the volume of gases that must be treated by the control system, and an increase in uncontrolled air emissions, including NO_X.

Thermal DeNOX

Thermal DeNOX is Exxon Research and Engineering Company's patented process for NO_X reduction. The process is a high temperature selective non-catalytic reduction (SNCR) of NO_X using ammonia as the reducing agent. Thermal DeNOX requires the exhaust temperature to be above 1,800°F. However, use of ammonia plus hydrogen lowers the temperature requirement to about 1,000°F. For some applications, this must be achieved by additional firing in the exhaust stream before ammonia injection.

The only known commercial applications are on heavy industrial boilers, large furnaces, and incinerators that consistently produce exhaust gas temperatures above 1,800°F. There are no known applications on or experience with CTs. Temperatures of 1,800°F require alloy materials constructed with very large piping and components since the exhaust gas volume would be increased by several times. As with the NOXOUT® process, high capital, operating, and maintenance costs are expected because of material requirements, an additional duct burner system, and fuel consumption. Uncontrolled emissions would increase because of the additional fuel burning.

The maximum exhaust gas temperature of an "F" Class combustion turbine is typically 1,100°F; the cost to raise the exhaust gas to such a high temperature is considered extremely expensive compared to other technically feasible control technologies. Thus, the Thermal DeNOX process will not be considered for the proposed project since its high application temperature makes it technically infeasible.

Selective Non-Catalytic Reduction

In SNCR systems, a reagent is injected into the flue gas in the furnace within an appropriate temperature window. Emissions of NO_X can be reduced by 30% to 50%. The NO_X and reagent (ammonia or urea) react to form nitrogen and water. A typical SNCR system consists of reagent storage, multi-level reagent-injection equipment, and associated control instrumentation. The SNCR reagent storage and handling systems are similar to those for SCR systems. However, because of higher stoichiometric ratios, both ammonia and urea SNCR processes require three or four times as much reagent as SCR systems to achieve similar NO_X reductions.

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[5] http://www.fueltechnv.com/NOXoutprocess.htm

The temperature window for efficient SNCR operation typically occurs between 1650°F and 2000°F depending on the reagent and condition of SNCR operation. When the reaction temperature increases over 1800°F, the NO_X removal rate decreases due to thermal decomposition of ammonia. On the other hand, the NO_X reduction rate decreases below 1800°F and ammonia slip may increase.

The exhaust temperature at the exit of the combustion turbines proposed for this project is approximately 1,100 ^{o}F, which is too low for any consideration of this technology. Temperatures in the range of 1,500 to 1,900 ^{o}F, along with adequate reaction time at this temperature, are required to use this technology. Due to the technical and operational limitations on temperature and available reaction time, this method of post-combustion control is determined to be technically infeasible for use in this project.

Non-Selective Catalytic Reduction (NSCR)

Stationary NSCR, involves the use of a three-way catalyst technology to promote the reduction of NO_X to nitrogen and water and simultaneous oxidation of CO and HC to carbon dioxide and water. NO_X is reduced by the CO and H_2 over the catalyst under slightly rich or stoichiometric conditions to produce CO_2 and water with typical conversion efficiencies in the range 80 to 99 percent, which is achievable together with decreases in HC and CO.

NSCR can be applied to various spark ignited internal combustion engines that are rich-burn, including natural gas-fueled engines. These types of engines are commonly found in the following applications: gas gathering and storage, gas transmission, power generation, combined heat and power, cogeneration/trigeneration, irrigation, inert gas production, and non-road mobile machinery. NSCR has been used routinely in the automotive industry to reduce vehicular carbon monoxide, hydrocarbons, and NO_X emissions with over a billion catalyst units equipped to automobiles since the mid-1970s. The application of NSCR to stationary gas engines for the control of NO_X and CO first became commercially available in North America in the late 1980s and there are well over 5,000 stationary engine installations in service today.

Technical Feasibility Analysis

Wet injection can be eliminated since it is less effective in gas firing applications than other control systems, and while technically feasible, it is generally not used in modern gas fired combined cycle units, and because DLN combustors would provide an equivalent or better control for no additional cost.

DLN Combustors are available, demonstrated, and technically feasible in this application, and will be considered for BACT.

SCR is available, demonstrated in numerous installations, and technically feasible in this application, and will be considered for BACT.

NOXOUT is eliminated because it has not been demonstrated on any large gas fired combustion turbine unit, along with the fact that it's required operation temperature of 1600°F to 1950°F is significantly above the maximum exhaust gas temperature of 1100°F the gas turbines in this project.

Thermal DeNOX is eliminated because it has not been demonstrated for combined cycle units, along with the fact that its required operation temperature of 1800°F is above the maximum exhaust gas temperature of 1100°F for this project.

SNCR is eliminated because it also requires high temperatures between 1600°F, and 2100°F for its reactions to happen; furthermore, there are no installed examples of this technology used on combined cycle gas turbines.

NSCR is eliminated because it requires low levels of O_2 in the treated exhaust stream. Combined cycle turbines operate with at least 12% excess oxygen, which makes NSCR a non-applicable control technology.

EMx is considered applicable only in theory; its manufacturer claims that the technology is scalable to larger turbine sizes, although at this time there are only 8 operating turbines using this type of control technology, and all are less than 50 MW. Technical problems associated with scaling up the EMx technology are unknown given the large differences in exhaust flow rates. EMx is available through commercial channels. The Division must therefore conclude that EMx is not demonstrated, since it has never been deployed in an application approaching 200 MW.

After reviewing the above information, the only technically feasible NO_X control technology available for gas-fired operation of the combustion turbines is SCR used in conjunction with DLN combustors.

Energy Impacts: The use of an SCR system impacts the energy requirements of the facility. The SCR system requires vaporizers and blowers to vaporize and dilute the aqueous ammonia reagent for injection. In addition, an SCR system catalyst will increase the backpressure on each combustion turbine, which will slightly reduce the power output of each combustion turbine.

Environmental Impacts: Collateral environmental concerns that were evaluated regarding SCR were the presence of ammonia emissions and the safety hazards associated with the transport, handling and storage of ammonia.

On page 4-17 of the application, the applicant stated that the maximum expected emission of ammonia will typically be less than 9 ppmvd, corrected to 15% O_2, with the potential to increase with increasing NH_3 feed rates. The amount of NH_3 slip at any facility will theoretically begin at near zero and tend to increase over the life of the catalyst.

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

Economic Impacts: The applicant provided a detailed cost analysis of installing SCR control equipment at Live Oaks Power Plant and three additional facilities with similar exhaust flow and pollutant removal efficiency ranges. Please see Appendix B for the detailed tables. The cost analysis for Live Oaks Power Plant assumes baseline emissions of 25 ppm using Dry Low NO_X burners. This is consistent with the guarantees available from Siemens for their SGT6-5000F class turbines. The analysis is based on the operating scenario submitted by the applicant of 200 startups and shutdowns per year, with 4000 hours of duct firing at 100% load, 2546 hours of 100% load with no duct firing, and 1752 hours of downtime per year. The cost per ton of pollutant removed will be more depending upon the actual number of startups and shutdowns per year, the load that the turbine is operated at, and whether or not duct firing is used.

Table 4-1: Economic Analysis for SCR

Control Option	Baseline Emissions (TPY)	Emissions w/ Controls (ppmvd)	Emissions w/Controls (TPY)	Emissions Reduction (TPY)	Total Annualized Cost	Cost Effectiveness ($/Ton)
SCR	683	2.5 ppmvd @ 15% O_2	87	596	$1,751,839	$2,939
DLN Combustors	683	25 ppmvd @ 15% O_2	683	Baseline	Baseline	Baseline

NO_X BACT Emissions Standard Analysis: Live Oaks proposed a NO_X BACT limit to be 2.5 ppmvd @ 15% oxygen on a 24-hour block average basis at the combined stack from the CT and duct burner in the HRSG.

Conclusions for NO_X

The Division has determined that the proposal to use DLN combustor technology in conjunction with SCR post-combustion air pollution control is acceptable, and meets the requirements of BACT. The NO_X BACT emission limit is set at 2.5 ppmvd at 15% oxygen. The averaging time of this emission limitation is tied to or based on the run time(s) specified by the applicable reference test method(s) or procedures required for demonstrating compliance (i.e., Method 7E – 3 hour averaging period, and measurement via CEMS). With the limit on a 3-hour averaging period, it is more restrictive than the 24-hour block average basis proposed by the applicant. However, the Division believes that this determination is consistent with recent BACT determinations.

A NO_X BACT emission rate of 2.5 ppmvd at 15% oxygen is equivalent to 21.5 lb/hr and 0.0092 lb/MMBtu with a maximum heat input of 2334 MMBtu/hr. [See Appendix B for the conversion from the concentration value to the mass emission values.] The annual NO_X BACT emission limit is set at 87 tons per year per CT/HRSG stack, and is based on the operating scenario submitted by the applicant of 200 startups and shutdowns per year, with 4000 hours of duct firing at 100% load, 2546 hours of 100% load with no duct firing, and 1752 hours of downtime per year. The annual NO_X BACT emission limit encompasses emissions generated during normal source operation (including startup and shutdown) and malfunctions. The short term NO_X BACT emission limits do not apply during startup and shutdown periods as defined in the permit, with the understanding that excess emissions may result during startup or shutdown as a normal part of operation.

Table 4-2: BACT Summary for NO_X from the Combustion Turbines

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
NO_X	Dry Low NO_X Burners with SCR	2.5 ppmvd at 15% oxygen	3-hours	CEMS
NO_X	Dry Low NO_X Burners with SCR	87 Tons Per Year	Monthly	CEMS

4.1.2 Carbon Monoxide and Volatile Organic Compounds

Gas turbine combustors were originally designed to operate with a near stoichiometric mix of fuel and air in the primary combustion zone. Reduction in NO_X emissions, through combustion modification, included reduced combustor residence time and lean pre-mix conditions. Shortening the residence time of the combustion products at high temperatures may result in increased carbon monoxide (CO) and hydrocarbons (HC) emissions if no other changes are made in the combustor. In order to minimize increases in CO and HC emissions, combustors with reduced residence time also incorporate design changes in the air distribution ports to promote turbulence, which improves air/fuel mixing and reduces the time required for the combustion process to be completed. According to the Gas Research Institute, the differences between reduced residence time combustors and standard combustors are the placement of the air ports, the design of the circulation flow patterns in the combustor, and a shorter combustor length. Note that in this discussion the word hydrocarbons are taken to mean volatile organic compounds (VOCs).

Summary of Control Technologies

In reviewing the BACT alternatives to control emissions of CO and VOC from each combustion turbine, Live Oaks considered good combustion practice along with two different post-combustion control technologies, catalytic oxidation and EMx.

Good Combustion Practice (GCP)

Combustion technology/design is a function of the design and efficient operation of the CTs. With combustion technology/design control, formation of CO and VOC in the CTs is minimized by good combustion efficiency through optimum design and operation. This includes proper air-to-fuel ratios, and a turbine design that provides the necessary temperature, residence time and mixing conditions in the combustion zone. As a result of economic incentives, as well as air pollution concerns, manufacturers have attempted to maximize the combustion efficiency of turbines.

Care must be taken when incorporating design changes to reduce both NO_X and CO emissions. CO emission combustion modifications can possibly increase NO_X emissions and vice versa. A balance between these air pollutants must be achieved in order for combustion modification to be useful.

EPD considers GCP as technically feasible and achievable in practice for the turbine and duct burners in question. No economic or environmental analyses were performed since this is the base case option.

Catalytic Oxidation

Catalytic oxidation is a post combustion control technique for reducing emissions of CO and hydrocarbons. A catalytic oxidation system is a passive reactor, which consists of a honeycomb grid of metal panels, typically coated with platinum or rhodium. The catalyst grid is placed in the engine exhaust where the optimum reaction temperature can be maintained (450^0F - 1200^0F). The oxidation process takes place spontaneously, without the requirement for introducing reactants (such as ammonia) into the flue gas stream. The catalyst serves to lower the activation energy necessary for complete oxidation of these incomplete combustion byproducts to carbon dioxide. The active component of most catalytic oxidation systems is platinum metal, which has been applied over a metal or ceramic substrate. As with SCR, minimization of pressure drop is a major design criterion; therefore, honeycomb catalyst designs are common.[6]

The primary limitation that may preclude the use of catalytic oxidation is frequent, wide load variations, which will reduce catalyst efficiency and may cause thermal shock degradation of the catalyst. EPD believes that catalytic oxidation is technically feasible and achievable in practice for the proposed modification.

Live Oaks considered combustion process design and catalytic oxidation for the reduction in CO emissions. Catalytic oxidation is also effective in reducing VOC emissions. There are no applicable state or federal regulations that specify the allowable CO or VOC emission limit.

EMx

EMx, previously known as SCONOX, also controls CO and VOC as discussed in section 4.1.1. The EMx system employs a single catalyst to oxidize CO to CO_2, and NO to NO_2. VOC destruction is greater than 80 percent for non-methane hydrocarbons and destruction of HAPs such as formaldehyde and acetaldehyde have been measured at 97 percent and 94 percent, respectively at 300° F. The percentage destruction is expected to rise at higher temperatures. As stated before, EMx is considered applicable in theory, as its manufacturer claims that the technology is scalable to larger turbine sizes. However, since technical problems associated with scaling up the EMx technology are unknown given the large differences in exhaust flow rates, EMx is not considered to be demonstrated for this class of equipment because it has never been deployed on any turbine larger than 50 MW.

Technical Feasibility Analysis

Because EMx has never been deployed in any application above 50 MW, it has not been demonstrated for this category of source. The use of Oxidation Catalyst in combination with proper combustor design 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.

Energy Impacts: An oxidation catalyst located downstream of the simple cycle CTG exhaust will increase the backpressure on the combustion turbine. The additional backpressure of each system will reduce the combustion turbine output by a small amount. These impacts have been converted to an annual cost and are included in the detailed cost analysis. Please see Appendix B for the detailed tables.

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[6] Discussion about catalytic oxidation is taken from the Gas Research Institute Web page Entitled "Combustion Turbine Design, Operation, and Control."

Environmental Impacts: The Division considered collateral impacts of the use of catalytic oxidation and determined that the primary environmental impact would be disposal of the spent catalyst.

Economic Impacts: This selection process will look at the use of catalytic oxidation, compared with proper combustor design and operation, which would be the baseline case. Cost analyses were presented by the applicant for their facility and three other facilities with similar exhaust flows, and control parameters. See Appendix B for the detailed tables. The supplied cost analysis only considered control of CO, whereas catalytic oxidation has been shown to also reduce emissions of VOC. For this reason the Division has added the tons of VOC and CO reduction from the application of catalytic oxidation, and determined a cost per ton removed of both pollutants.

For the cost analysis, the baseline uncontrolled emissions are assumed to be from operation of the turbines at 100% load with duct firing, and operation for 8760 hrs/year. The real tons removed will be less depending on the actual operation of the facility, with changes due to more or fewer startups and shutdowns, and the amount of duct firing that will be done. The control efficiency of the catalytic oxidation equipment will vary greatly depending on this schedule, with corresponding effects on the cost per ton of pollutant removed.

Table 4-3: Economic Analysis for Catalytic Oxidation

Control Option	Baseline Emissions (TPY)	Emissions w/Controls (ppmvd)	Emissions w/Controls (TPY)	Emissions Reduction (TPY)	Total Annualized Cost	Cost Effectiveness ($/Ton)
Catalytic Oxidation	CO=348 VOC=88	CO=3.2 VOC=2	CO=73 VOC=26	CO=275 VOC=62	$710,193	$2,107
Good Combustion Practices	CO=348 VOC=88	CO=15.2 VOC=6.7	CO=348 VOC=88	Baseline	Baseline	Baseline

CO and VOC BACT Emission Standard Analysis: The Division is aware that typical turbine vendor guarantees for CO/NO_X limits for combustors are dependent on the tuning for NO_X. In other words, the turbine vendor is able to tune their combustors for very low NO_X emissions at the expense (or possibility) of increasing CO emissions. However, the Division believes that the actual uncontrolled emission rates of both CO and VOC will be lower in operation than what the applicant proposed. Turbine vendor performance guarantees are now only catching up with field experience. The applicant proposed BACT limits for CO of 2.0 ppmvd at 15% oxygen without duct firing, and 3.2 ppmvd @ 15% oxygen with duct firing, on a 3-hour average. They proposed VOC limits of 1.0 ppmvd @15% oxygen without duct firing, and 7.4 ppmvd @ 15% oxygen with duct firing, on a 3-hour average.

The most stringent CO emission rates for a combined-cycle facility with duct firing were found in Connecticut, set at 1.7 ppmvd @ 15% Oxygen, with duct firing, this same facility is limited to .9 ppmvd @15% oxygen without duct firing, averaged over 1 hour. For VOC, emission limits as low as 1 ppmvd at 15% oxygen, averaged over 1 hour were found. CO and VOC emissions at this level are typically only achieved with add-on controls. Good combustion practice alone cannot achieve these emission rates. The applicant provided several recently determined BACT limits in their application, that were extracted directly out of the EPA RACT/BACT clearing house database, and the National CT spreadsheet.

Conclusions for Carbon Monoxide and Volatile Organic Compounds

The Division has reviewed the applicant’s analysis, and concludes that catalytic oxidation along with good combustion practices should be chosen as BACT in this case. The Division believes that the approximate cost per ton of combined CO and VOC removed using an oxidation catalyst on each CT/HRSG is cost effective. BACT is set at 2.0 ppmvd at 15% oxygen for CO without duct firing, 3.2 ppmvd at 15% oxygen for CO with duct firing, and 2.0 ppmvd for VOC, with or without duct firing. Based on emissions data from other turbine installations, the Division believes that actual CO and VOC emissions may be lower than these BACT limits during normal operation without the use of an oxidation catalyst. However, during power augmentation and lower turbine loads, CO emissions will increase, making the catalytic oxidation control equipment necessary to meet the limits set. Actual VOC emission have been found to generally not vary with duct firing, vs. without duct firing; for this reason the Division has determined that a VOC limit of 2 ppmvd at 15% oxygen, with or without duct firing, is BACT.

A CO BACT emission rate of 2.0 ppmvd at 15% oxygen without duct firing is equivalent to 0.0045 lb/MMBtu or 8.9 lb/hr with a maximum heat input of 1990 MMBtu/hr. A CO BACT emission rate of 3.2 ppmvd at 15% oxygen with duct firing is equivalent to 0.0072 lb/MMBtu or 16.7 lb/hr with a maximum heat input of 2334 MMBtu/hr. [See Appendix B for the conversion from the concentration value to the mass emission values.] The annual CO BACT emission limit is set at 208 tons per year per CT/HRSG stack, and is based on the operating scenario submitted by the applicant of 200 startups and shutdowns per year, with 4000 hours of duct firing at 100% load, 2546 hours of 100% load with no duct firing, and 1752 hours of downtime per year. The annual CO BACT emission limit encompasses emissions generated during normal source operation (including startup and shutdown) and malfunctions. The short term CO BACT emission limits do not apply during startup and shutdown periods as defined in the permit, with the understanding that excess emissions may result during startup or shutdown as a normal part of operation. CO emissions during startup are significantly greater than during steady state operations because of incomplete combustion that takes place when the equipment is cold. Startup emissions of CO are much less for warm starts and hot starts than for cold starts.

A VOC emission rate of 2.0 ppmvd at 15% oxygen is equivalent to 0.0026 lb/MMBtu or 5.98 lb/hr per CT/HRSG, with a maximum heat input of 2334 MMBtu/hr. The VOC emission rate is set for the combined CT/HRSG stack and includes those times with and without duct firing, but not during startup and shutdown periods. Although no annual VOC BACT limit is being set, the VOC emission rate, on a concentration basis, equates to 41.3 tpy per combined CT/HRSG system for the same operating scenario given for CO.

Table 4-4: BACT Summary for CO and VOC from the Combustion Turbines

Pollutant	Control Technology	Proposed BACT Limit	Averaging Time	Compliance Determination Method
CO	Good Combustion Practices with Catalytic Oxidation	2.0 ppmvd at 15% oxygen w/o DB 3.2 ppmvd at 15% oxygen w/DB	3-Hours	CEMS
CO	Good Combustion Practices with Catalytic Oxidation	208 Tons Per Year, including SU/SD	Monthly	CEMS
VOC	Good Combustion Practices with Catalytic Oxidation	2.0 ppmvd at 15% oxygen with or without DB	3-Hours, Based on applicable test method	Performance Test

4.1.3 Particulate Matter

Emissions of particulate matter (PM) and particulate matter less than 10 microns in diameter (PM_{10}) from a CT results from fuel sulfur, inert trace contaminants, mercaptans in the natural gas, dust drawn in from the ambient air, particles of carbon and metals worn from the equipment while in operation, and condensable hydrocarbons resulting from incomplete combustion. All of the particulate matter emitted from the proposed CT is believed to be less than 10 micrometers in diameter, with most of it being less than 2.5 micrometers in diameter. Consequently, the Division assumes the worst-case scenario that all of the PM emissions are in effect $PM_{2.5}$, and will use measured PM_{10} emissions as a surrogate for $PM_{2.5}$.

Particulate matter emissions can be classified as "filterable" or "condensable" particulate matter. Filterable particulate matter is that portion of the total particulate matter that exists in the stack in either the solid or liquid state and can be measured on an EPA Method 5 filter. Condensable particulate matter is that portion of the total particulate matter that exists as a gas in the stack but condenses in the cooler ambient air to form particulate matter. Condensable particulate matter exists as a gas in the stack, so it passes through the Method 5 filter and is typically measured by analyzing the impingers, also known as the "back half" of the sampling train. Condensable particulate matter is composed of organic and inorganic compounds and is generally considered to be less than 1.0 micrometer in aerodynamic diameter. [*This discussion was taken from AP-42-Stationary Gas Turbines.*]

There are no applicable state or federal rules which specify the allowable PM or PM_{10} emission rates from the combustion turbine portion of a combined-cycle system. The heat recovery steam generator (HRSG) and duct burner are considered "fuel-burning equipment" as defined in Georgia Rule 391-3-1-.01(cc). There are no applicable federal rules which specify the allowable PM or PM_{10} emission rates from the duct burner. Georgia Rule 391-3-1-.02(2)(d)2.(ii) specifies the allowable PM emission rate from the duct burners. With a maximum heat input of 359 MMBtu/hr, the maximum allowable particulate matter emission rate per duct burner under Georgia Rule (d) is 0.1 lb/MMBtu, or 35.9 lb/hr at design heat input.

Technical Feasibility Analysis

The PM_{10} emission rate is partially dependent on fuel sulfur and nitrogen content. Natural gas has negligible amounts of fuel-bound nitrogen. As a result, there should be negligible nitrate production from any fuel-bound nitrogen. The production of thermally-induced nitrates and the organic fraction of PM_{10} can be abated through the use of combustion controls. On new gas turbines with state of the art combustion design, PM_{10} is most effectively reduced through use of fuels with both lower sulfur content and low ash content. Given the high combustion efficiency of the turbines and the firing of clean fuels, the PM and PM_{10} emissions should be very low. The installation of a particulate control device on a turbine firing clean fuels is considered to be impractical, in part because CTs generate an exhaust stream with a low concentration (i.e., < 0.01 gr/acf) and small particle diameters. Natural gas contains essentially no inert solids (ash). A review of EPA's BACT/LAER Clearinghouse documents did not reveal any post-combustion particulate control technologies being used on gas or oil fired CTs to control PM and PM_{10} emissions.

The combustion turbines will have lubricating oil demister vents. The demister is a knock out drum that is used to remove entrained lubricating oil. The vent is used to release the pressure on the system. Live Oaks did not calculate particulate matter emissions from such vents.

Based on the PSD permit application for the Duke Energy Murray, LLC facility, fugitive emissions from lube oil demister vents can be as high as 0.01 gallons of lube oil per day during normal operation. Assuming a density for lube oil of 8 pounds per gallon, this equates to potential emissions of 29.2 pounds per year. The Division believes that these emissions are clearly trivial and do not justify an emission limit. BACT for PM/PM_{10} emissions from the lube oil demister system would be proper design that includes a demister.

The only technically feasible option is the use of pipeline quality natural gas coupled with air inlet cooler/filter, lube oil vent coalescer (demister) and proper combustion design and operation.

Particulate Matter BACT Emission Standard Analysis: The Division reviewed the available information for $PM/PM_{10}/PM_{2.5}$ BACT emission limits from combined-cycle plants with duct firing within the last 6 years. According to this information, the $PM/PM_{10}/PM_{2.5}$ BACT limits were between 6 lb/hr and 38 lb/hr and Method 5 was the reference test method for compliance determinations. Method 5 only provides a test for filterable PM and not condensable. Live Oaks proposed a PM BACT emission limit of 10.3 lb/hr without duct firing, and 12.6 with duct firing. or 0.0044 to 0.0054 lb/MMBtu, respectively, in their application. The predicted particulate matter emission rate, as reported by Siemens-Westinghouse, is from 8 to 9 lb/hr, depending on ambient and load conditions. Based on information in the Live Oaks PSD permit application, the duct burner vendor anticipates negligible $PM/PM_{10}/PM_{2.5}$ emissions resulting from the operation of the duct burner.

The Division has carefully considered the available information for setting the $PM/PM_{10}/PM_{2.5}$ BACT emission limits. The Division is not solely relying on the results of source tests because the Division believes that they only provide a "snapshot" of the operation of the turbine; the results do not substantiate a BACT (achieved in practice) determination since the testing does not capture the entire operating range of the turbine. In determining whether a level of control has been demonstrated in practice, the Division, like EPA, focuses on the extent to which the source would have been in compliance if it had been operating under a permit that required that level of control[7]. The proposed PM/PM_{10} BACT emissions limit of 12.6 lb/hr or 0.0054 lb/MMBtu, based on 2334 MMBtu/hr heat input, appears to be consistent with other PSD permits for natural gas fired combined-cycle plants with duct firing.

Conclusions for Particulate Matter

Given the high combustion efficiency of the turbines and the firing of clean fuels, the PM and PM_{10} emissions should be very low. The Division has determined that the Live Oaks proposal to fire only pipeline quality natural gas, as well as use an air inlet cooler/filter, lube oil vent coalescer (demister) and proper combustion design and operation, meets the requirements of BACT for PM and PM_{10}. Hence, BACT for PM_{10} is the use of pipeline quality natural gas as defined in 40 CFR Part 72.2. The Division will not require initial or subsequent performance tests or ongoing monitoring because it is assumed that, as long as the facility meets the fuel quality requirements, their emissions will consequently be under the expected 0.0054lb/MMBtu emission rate.

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[7] EPA Letter to Goal Line dated July 2, 1997

Table 4-5: BACT Summary for PM/PM_{10}/$PM_{2.5}$ Emission from the Combustion Turbines

Pollutant	Control Technology	Proposed BACT Limit	Compliance Determination Method
PM/PM_{10}/$PM_{2.5}$	Pipeline Quality Natural Gas limited to .5 grains sulfur /100 scf	Fire Pipeline Quality Natural Gas Only - No emission limit set	Fuel purchase records submittal

4.1.4 Sulfur Dioxide and Sulfuric Acid Mist

Sulfur dioxide (SO_2) is emitted as a result of the oxidation of the sulfur in the fuel. The combined-cycle power block will be fired exclusively with natural gas. Natural gas does contain a small amount of sulfur, including sulfides and sulfur-containing mercaptan, which is added to natural gas to permit leak detection. Therefore, a small amount of SO_2 is produced in the combustion of natural gas.

Sulfuric acid mist emissions are formed as a result of a small percentage of the SO_2 in the flue gas oxidizing to SO_3 that combines with water to form H_2SO_4.

40 CFR 60.4330 [40 CFR 60, Subpart KKKK] limits SO_2 emissions to 0.9 lbs/MW-hr from the combustion turbine and duct burner combined. The combustion turbine is a “fuel-burning source” and therefore is subject to Georgia Rule 391-3-1-.02(g)2. Georgia Rule (g)2 specifies an allowable fuel sulfur content of 3.0 weight percent since the turbine has a maximum heat input greater than 100 MMBtu/hr.

The heat recovery steam generator (HRSG) and duct burner constitute a “fuel-burning source” and therefore the duct burner is subject to Georgia Rule 391-3-1-.02(g)2. Georgia Rule (g)2 specifies an allowable fuel sulfur content of 3.0 weight percent since the duct burner has a maximum heat input of greater than 100 MMBtu/hr.

Table 4-6: SO_2 Emission Standards

Unit	SO_2 Emission Rate/Sulfur Fuel Content	Source of Emission Rate
Combined Cycle CT/Duct Burner	0.9lbs SO_2/MW-hr power output or a maximum fuel content of 0.06 lbs/MMBtu fuel input	40 CFR 60, Subpart KKKK [40 CFR 60.4330]

Technical Feasibility Analysis

Identified as pollution prevention in many of the RBLC database entries, use of a fuel containing low sulfur content is considered a control technology. The lowest sulfur containing fuel available in large quantities is natural gas. The definition of pipeline quality natural gas in 40 CFR 72.2 includes a maximum sulfur content of 0.5 grains/100 scf, as well as minimum and maximum fuel heating values (FHV) of 95,000 and 110,000 BTU/100 scf, respectively. Using the equation for natural gas with less than 20 grains sulfur/100scf in 40 CFR 75 appendix D to calculate the lb/MMBtu sulfur emissions, and assuming the lowest allowable fuel heating value for pipeline quality natural gas, the emission limit is set at 0.0015 lb/MMBtu, resulting in extremely low SO_2 emissions. In 40 CFR 75 appendix D specifies using an emission rate of 0.0006lb/MMBtu to estimate SO2 emissions where all annual gas samples, or tariff sheets have shown the fuel to contain less than 0.5 grains sulfur/100scf of gas. Use of pipeline quality natural gas is technically feasible and is proposed as a BACT avoidance limit for control of SO_2 and H_2SO_4 emissions from the CT/HRSG system by Live Oaks.

Sulfur Dioxide and Sulfuric Acid Mist BACT Emission Standard Analysis: The only BACT alternative that Live Oaks considered is the exclusive use of natural gas in the CT/HRSG systems. The use of low and very low sulfur fuels have established records of compliance when used in combustion equipment such as CTs and duct burners. Therefore, the very low SO_2 emission rate that results from the use of pipeline natural gas represents the top level of SO_2 emissions control for a CT.

Conclusions for Sulfur Dioxide and Sulfuric Acid Mist

With extremely low emission rates of SO_2, and H_2SO_4, it is proposed that the use of pipeline quality natural gas be considered a BACT avoidance limit for SO_2 and H_2SO_4. There are no fuels available with lower sulfur content, and given the large exhaust gas volume from the combustion turbines and extremely low SO_2 concentrations, further reducing SO_2 emissions would be practically impossible. The use of pipeline quality natural gas over other types of fuels is considered cost effective, although no cost analysis was performed for this fuel option. The Division has determined that the Live Oaks proposal to only fire pipeline quality natural gas containing .5 grains sulfur/100 scf or less, as defined in 40 CFR 72.2, in the CT/HRSG systems, makes the facility not subject to BACT for SO_2 and H_2SO_4.

Table 4-7: BACT Avoidance Summary for Sulfuric Acid and Sulfuric Acid Mist Emissions from the Combustion Turbines

Pollutant	Control Technology	Proposed BACT Avoidance Limit	Averaging Time	Compliance Determination Method
SO_2, and H_2SO_4 mist	Pipeline Quality Natural Gas limited to .5 grains sulfur /100 scf	Clean Fuel Usage, 0.5 grains sulfur /100 scf	n/a	Fuel purchase records submittal

4.2 Fuel Gas Heater

A fuel gas heater will be installed to operate in conjunction with combustion turbines. This heater will preheat the natural gas prior to its introduction into the combustion turbines in order to provide the optimum combustion efficiency. The fuel gas heater is rated at 10 MMBtu/hr and will be fired by pipeline natural gas only. For SO_2 and PM_{10} emissions, the primary determinant of emissions is the sulfur content of the fuel. The Division proposes, as BACT for PM and PM_{10} emissions, and as BACT avoidance for SO_2 and sulfuric acid mist, to fire only pipeline natural gas as fuel (maximum sulfur content 0.5 grains/100 standard cubic feet as defined in 40 CFR 72.2). For NO_X, CO, and VOC, BACT is proposed as “Good Combustion Practice.

4.3 Auxiliary Equipment

One diesel emergency generator will be installed to provide emergency power for maintaining plant control and critical systems operations during emergencies. The generator, rated at 600 kW, will not be operated more than 500 hours per year, and is not intended to provide power for a black start. The facility is equipped with one 310 hp firewater pump. The firewater pump is powered by a diesel engine. The pump will be used for fire fighting purposes, and the diesel pump is expected to operate less than 500 hours per year.

For SO_2, sulfuric acid mist, PM, and PM_{10} emissions, the primary determinant of emissions from the emergency generators and fire pump, is the sulfur content of the fuel. Live Oaks proposed, as BACT for SO_2 and PM_{10} emissions, to fire diesel fuel containing a maximum sulfur content of 0.05 weight percent. The division will accept a limit on the fuel sulfur content as BACT for PM and PM_{10}, but will require ultra low sulfur diesel fuel which is limited to 0.0015 weight percent, or 15 ppm. The same sulfur limit will act as BACT avoidance for SO_2, and sulfuric acid mist. For NO_X, BACT is proposed as limiting the hours of operation of each to 500 hours per rolling year, which is feasible due to the non-routine nature of their operation. Emissions of NO_X, CO and particulate matter from both the emergency generator and the firewater pump are also regulated by 40 CFR Part 60, Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines.

4.4 Cooling Towers

The project will include a cooling tower. EPA's publication entitled AP-42 provides an estimate of potential emissions from cooling towers. However, the emission estimates have very low quality ratings, so the data should not be automatically accepted. Particulate emissions are generated from wet cooling towers in the form of drift. Drift is formed when droplets of water are entrained in the exhaust gas stream passing through the cooling tower. As the water in the droplets evaporates, the solids in the water become particulate matter. The only control method available for wet cooling towers is drift eliminators. The design of the drift eliminators dictates their control efficiency or ability to eliminate water droplets from becoming entrained in the exhaust gas stream. The cooling tower for this project will employ high efficiency drift eliminators to control water carryover into the atmosphere and therefore reduce particulate emissions. This type of design should keep drift to 0.001% of flow. This is in contrast to a default drift value of 0.02% used in the AP-42 document (a factor of 20 lower). The Division agrees with Live Oaks that the high efficiency drift eliminators will minimize any potential emissions from the cooling tower. Hence, the Division assumes negligible PM/PM_{10} emissions from the cooling tower and that BACT is proper design and operation of the cooling tower/drift eliminators. The use of drift eliminators has an established record of compliance with emission regulations and is considered BACT for similar units.

5.0 TESTING AND MONITORING REQUIREMENTS

5.1 Combustion Turbine & Duct Burner

Requirements for NO_X

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

Continuous compliance with the NO_X emission limitations of Subpart KKKK will be demonstrated with a NO_X CEMS on each CT/HRSG stack, in keeping with 40 CFR 60.4335(b)(1), 60.4340(b)(1), and 60.4345. Each NO_X CEMS must be installed and certified according to Performance Specification 2 of 40 CFR Part 60, Appendix B, except that the 7-day calibration drift is to be based on unit operating days, not calendar days. The Acid Rain Regulations also require continuous monitoring and recording of NO_X emissions. Therefore the NO_X CEMS meet the requirements for several regulations, including BACT, NSPS, and Acid Rain. The installation of a diluent monitor along with the CEMS in the stacks is also required to allow calculation of total NO_X emissions from each CT/HRSG stack in lb/MMBtu.

Data from the NOx CEMS must be used to calculate hourly NO_X emission rates. Three-hour rolling NO_X emission averages derived from the hourly NO_X CEMS data, will satisfy the periodic monitoring requirement for the BACT NO_X emission limits. The hourly measurements must also be used to calculate a 30-day rolling NO_X emission average total to assure compliance with the Subpart KKKK NO_X emission limits. The BACT emission limits are more stringent at 2.5 ppm, versus the 15 ppm limit contained in the NSPS. Excess emissions, as defined in the NSPS, will consist of any unit operating period in which the 30-day rolling average NO_X emission average exceeds 15 ppmvd at 15% O_2.

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

Requirements for CO

Compliance with the BACT CO emission limitations for each combustion turbine and its paired duct burner must be demonstrated by the use of CO CEMS. Because the Division is requiring the use of a CO CEMS (discussed below), initial and annual CO performance testing is not required.

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

Requirements for SO_2

NSPS Subpart KKKK requires the total sulfur content of the fuel to be monitored. However, if a fuel is demonstrated not to exceed potential sulfur emissions of 0.06 lb SO_2/MMBtu heat input, then the Permittee may elect not to monitor the sulfur content of that fuel. Instead of requiring daily monitoring of the sulfur content of the natural gas, the Permittee may submit an analysis of the sulfur content of the natural gas contained in a current valid purchase contract, tariff sheet or transportation contract. In keeping with the provisions of 40 CFR 60.4365, the Permittee will therefore demonstrate that the pipeline quality natural gas does not contain potential sulfur emissions in excess of 0.06 lb SO_2/MMBtu. The Acid Rain regulations require that SO_2 mass emissions from each combustion turbine and its paired duct burner be measured and recorded. One option for satisfying that requirement is to use applicable procedures specified in Appendix D to 40 CFR Part 75 for estimating hourly SO_2 mass emissions. SO_2 mass emissions from firing pipeline quality natural gas will be estimated using the regulatory default SO_2 emission rate of 0.0006 lb SO_2/MMBtu and the applicable quantity of natural gas burned in the combustion turbine and its paired duct burner. Pipeline natural gas is defined in 40 CFR Part 72 as having a maximum sulfur content of 0.5 grains/100 scf; an excursion will result if this limit is exceeded.

Requirements for VOC

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

Requirements for Particulate Matter and Opacity

The combustion turbine component of each combined-cycle system will only be able to fire natural gas. Natural gas 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 comfortably below their allowable levels with no controls, performance testing or continuous monitoring for particulate matter and visible emissions will not be required. Method 9 also will be the basis for periodic monitoring of visible emissions, if 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 emissions without the need for any other periodic monitoring.

Summary of Testing Requirements

1. The permit includes a performance test on each combined CT/HRSG stack for NO_X emissions while burning natural gas, at 100% load plus or minus 25%, to verify compliance with the NO_X BACT emission standard and the initial performance testing required by 40 CFR 60.8

2. VOC emissions must be verified through conducting performance tests on each stack at base load with the duct burner firing, and at 60 percent load without the duct burner firing.

Summary of Monitoring Requirements

1. Emissions of NO_X shall be continuously monitored and recorded, in the combined stack of each CT/HRSG system, which will verify compliance with the NO_X concentration emission standard of 2.5 ppmvd @ 15% O_2 during normal operation. To demonstrate compliance with the long term NO_X emission standard, which must include periods of startup, shutdown, and malfunction, the Permittee is required to maintain monthly records that specify the twelve consecutive month total NO_X emissions (in tons) from each combined-cycle system. Failure to maintain NO_X emissions from either combined-cycle system below 87 tons during any twelve consecutive months must be reported as an exceedance.

2. Emissions of CO shall be continuously monitored and recorded, in the combined stack of each CT/HRSG system, which will verify compliance with the CO concentration emission standard of 2 ppmvd @ 15% O_2 during normal operation, and of 3.2 ppmvd @15% O_2 during duct firing. To demonstrate compliance with the long term CO emission standard, the Permittee is required to maintain monthly records that specify the twelve consecutive month total CO emissions (in tons) from each combined-cycle system. Failure to maintain CO emissions from either combined-cycle system below 208 tons during any twelve consecutive months must be reported as an exceedance.

3. The Division believes that the operation of each combined-cycle system will be in compliance with the short term VOC limit as long as the emission are in compliance with the short term CO emissions limit.

4. To monitor SO_2 the Permittee shall submit an analysis of the fuel quality characteristics contained in a current valid purchase contract, tariff sheet, or transportation contract verifying that the natural gas contains less than 0.5 grains of sulfur per 100 standard cubic feet. Failure to comply with this fuel sulfur limit must be reported as an excursion.

5.2 Auxiliary Equipment

Auxiliary equipment includes the fuel gas heater, emergency generator, firewater pump, cooling tower, and lube oil demister vents. The fuel gas heaters are subject to PSD BACT emission standards for NO_X and a PSD BACT work practice standard for PM/PM_{10} emissions. The PSD BACT work practice standard specifies that the Permittee shall only fire pipeline quality natural gas in the fuel gas heater. No additional monitoring is prescribed to verify compliance with this standard. No additional monitoring is prescribed for NO_X and CO emissions.

Sulfur dioxide and particulate matter emissions from the diesel IC engines are minimized through the use of ultra low sulfur diesel fuel (maximum sulfur content of 0.0015 weight percent, 15 ppm) and by limiting operation to 500 hours per year.

Verification of compliance with the fuel sulfur limit will be tracked by obtaining fuel supplier certifications. Verification of compliance with the operational limit will be done by monitoring and recording the operational time. 40 CFR 60 Subpart IIII is also applicable to the firewater pump, and emergency generator, and requires the monitoring of operational time using a non-re-settable hour meter.

Verification of compliance with the operation limit of 500 hours per year will be tracked on a monthly basis. Cumulative total hours of operation for each of the following equipment, emergency generator EG1 and firewater pump FP1, must remain below 500 hours per year.

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

5.3 CAM Applicability

The combustion turbines and duct burners are subject to the requirements of compliance assurance monitoring (CAM) as specified in 40 CFR 64. CAM is only applicable to emission units that have potential emissions greater than the major source threshold, are located at a major source, use a control device to control a pollutant emitted in an amount greater than the major source threshold for that pollutant, and have a specific emission standard for that pollutant. The combustion turbines and duct burners use selective catalytic reduction and an oxidation catalyst to control NO_X, CO, and VOC emissions. CAM is applicable for these pollutants because (1) the permit contains emission limitations for each pollutant, (2) a control device will be utilized to meet the emission limitation, and (3) without the control device, the emissions from each unit would exceed the major source thresholds (100 tons per year for CO, VOC and NOx). Furthermore, because the post control emissions of each of these pollutants exceed the major source thresholds, these units are considered large pollutant specific emission units (PSEUs). Live Oaks Power Plant will be required to submit a CAM plan with the Title V application within 1 year after the facility commences commercial operation.

6.0 AMBIENT AIR QUALITY REVIEW

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

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

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 PM, PM_{10}, VOC, NO_X, and CO that are greater than the applicable PSD Significant Emission Rates. Therefore, air dispersion modeling analyses are required to demonstrate compliance with NAAQS and/or PSD Increment. VOC does not have established PSD modeling significance levels (MSL) (an ambient concentration expressed in either $\mu g/m^3$ or ppm), so modeling is not required for VOC emissions. However, this is not a concern since the relative VOC emissions are very small, and the project will likely have no impact on ozone attainment in the area, based on data from the monitored levels of ozone in Glynn County and the level of emissions increases that will result from the proposed project. In any case, the southeast is generally NO_X limited with respect to ground level ozone formation.

Significance Analysis: Ambient Monitoring Requirements and Source Inventories

Initially, a Significance Analysis was conducted to determine if the PM, PM_{10}, VOC, NO_X, and CO emissions at the Live Oaks Power Plant would significantly impact the area surrounding the facility. Maximum ground-level concentrations were compared to the pollutant-specific U.S. EPA-established Significant Impact Levels (SILs). The SILs for the pollutants of concern are summarized in Table 6-1.

If a significant impact (i.e., an ambient impact above the SIL) does not result, no further modeling analyses need be conducted for that pollutant for NAAQS or PSD Increment. If a significant impact does result, further refined modeling must be done 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 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 listed in Table 6-1. If either the predicted modeled impact from an emission increase or the existing ambient concentration is less than the monitoring *de minimis* concentration, the permitting agency has the discretionary authority to exempt an applicant from pre-construction ambient monitoring. This evaluation was required for PM, PM_{10}, NO_X, and CO.

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

Table 6-1: Summary of Modeling Significance Levels

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

NAAQS Analysis

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

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

Pollutant	Averaging Period	NAAQS	
		Primary / Secondary (ug/m^3)	Primary / Secondary (ppm)
PM_{10}	Annual	*Revoked 12/17/06	*Revoked 12/17/06
	24-Hour	150 / 150	--
$PM_{2.5}$	Annual	15 / 15	--
	24-Hour	35 / 35	--
NOX	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 Live Oaks Power Plant, 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 all new emission units. Facility emissions would then be combined with the allowable emissions of sources included in the regional source inventory. The resulting impacts, added to appropriate background concentrations, would be assessed against the applicable NAAQS to demonstrate compliance. For an annual average NAAQS analysis, the highest modeled concentration among five consecutive years of meteorological data would be assessed, while the highest second-high impact would be assessed for the short-term averaging periods.

PSD Increment Analysis

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

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

Table 6-3: Summary of PSD Increments

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

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

The determination of whether an emissions change at a given source consumes or expands increment is based on the source classification (major or minor) and the time the change occurs in relation to baseline dates. The major source baseline date for NOX is February 8, 1988, and the major source baseline for SO_2 and PM_{10} is January 5, 1976. Emission changes at major sources that occur after the major source baseline dates affect Increment. In contrast, emission changes at minor sources only affect Increment after the minor source baseline date, which is set at the time when the first PSD application is completed in a given area, usually arranged on a county-by-county basis. The minor source baseline dates have been set for PM_{10} and SO_2 as January 30, 1980, and for NO_2 as April 12, 1991.

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

Originally, the modeling analysis was submitted without including the startup and shutdown conditions for the combustion turbines. This decision was based on the very short duration period of these events, which ranges from 45 min to almost 4 hours. However, considering their high emission rates, their frequency of occurrence, and the fact that some of the averaging periods for the NAAQS are also very short, it was decided during the Division's review process to include startup/shutdown emissions in all the short-term modeling.

Given that these types of power plants can operate at different capacities, their emission rates can vary according to the fuel load, and therefore the predicted concentration in a modeling exercise will be a variable dependent not only on this factor, but also on the ambient temperature. Due to this reason, a first modeling analysis (fuel load analysis) was conducted prior to the significance modeling, using a generic emission rate to assess the impact caused by each possible scenario of operating conditions. Once the fuel load and ambient temperature that would cause the highest impact on air quality were determined, they were used to run AERMOD for the significance assessment.

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

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

Pollutant	Averaging Period	Year*	UTM East (km)	UTM North (km)	Maximum Impact (ug/m^3)	SIL (ug/m^3)	Significant?
NO_2	Annual	1994	4466000	3461200	0.6854	1	No
PM_{10}	24-hour	1993	447400	3461000	1.91169	5	No
	Annual	1992	447400	3461000	0.15260	1	No
CO	1-hour	1993	447400	3461000	869.56	2000	No
	8-hour	1993	447200	3461100	194.54	500	No

* Data for worst year provided only.

Ambient Monitoring Requirements

Table 6-5: Significance Analysis Results – Comparison to Monitoring *De Minimis* Levels

Pollutant	Averaging Period	Year*	UTM East (km)	UTM North (km)	Monitoring De Minimis Level (ug/m^3)	Modeled Maximum Impact (ug/m^3)	Significant?
NO_2	Annual	1994	446600	3461200	14	0.6854	No
PM_{10}	24-hour	1993	447400	3461000	10	1.91169	No
CO	8-hour	1993	447200	3461100	575	194.54	No

* Data for worst year provided only

The impacts for NO_X, CO, SO_2, and PM_{10} quantified in Table 6-4 of the Class I Significance Analysis are compared to the Monitoring *de minimis* concentrations, shown in Table 6-1, to determine if ambient monitoring requirements need to be considered as part of this permit action. Because all maximum modeled impacts are below the corresponding de minimis concentrations, no pre-construction monitoring is required for NO_2, PM_{10}, 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 Brunswick at Risley Middle School) 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 pollutant to distance ratio calculation has been used to determine if a Class I area may be affected. The tons per year of all visibility affecting pollutants are added, and divided by the distance to the Class I area in km (Q/D). If the ratio is greater than 4, then impacts to that Class I area are modeled.

The two Class I areas with Q/D ratios greater than 4 are the Okefenokee National Wildlife Refuge, located approximately 64 kilometers southwest of the facility; and the Wolf Island National Wilderness Area, located approximately 23 kilometers east-northeast of the facility. The U.S. Fish and Wildlife Service (FWS) is the designated Federal Land Manager (FLM) responsible for oversight of both of these Class I areas. The FWS asked the Division to also consider impacts to three other Class I areas in our analysis. They are St. Marks National Wildlife Refuge in FL, located approximately 290 kilometers southwest; Chassahowitzka National Wildlife Refuge in FL, located approximately 298 kilometers south-southwest; and Cape Romain National Wildlife Refuge in SC, located approximately 253 kilometers northeast. In compliance with the FLM's request, all five Class I areas were included in the significance and AQRV assessments despite the low emissions/distance ratio for three of them.

Class I Significant Impact Analysis

The Class I significant impact analysis was conducted using the EPA-approved version of CALPUFF (Version 5.8 Level 070623) along with the postprocessors POSTUTIL (Version 1.56 Level 070627) and CALPOST (Version 5.6394 Level 070622). For Wolf Island NWR, because of the close proximity to the proposed facility, the Class I significant impact analysis was conducted using AERMOD (version 07026).

Concentrations of PM10 and NO_2 were modeled and compared to the Class I Significant Impact Levels (SILs) in order to determine if a full Class I increment analysis would be necessary. Some corrections were made during EPD's review of the PM10 post-processing stage of the modeling, adding a POSTUTIL run to include the contribution of sulfates and nitrates to the PM10 concentration. Results of the maximum predicted concentration for the corresponding averaging periods are shown in Tables 6-6 through 6-10 for each of the previously mentioned Class I areas.

Table 6-6: Project Impacts Vs. Significance Levels (Okefenokee Class I Area)

Criteria Pollutant	Averaging Period	Significance Level	Maximum Predicted Concentration*	Receptor Location UTM ZONE 17		Model Met Data Period
		(µg/m^3)	(µg/m^3)	X	Y	[mmddyyyy]
PM10	Annual	0.2	0.0021	390583	3427672	2002
	24-Hour	0.3	0.0406	390411	3427672	12192002
NOx	Annual	0.1	0.0037	390582	3427672	2002

* Highest value.

Table 6-7: Project Impacts Vs. Significance Levels (Wolf Island Class I Area)

Criteria Pollutant	Averaging Period	Significance Level	Maximum Predicted Concentration*	Receptor Location UTM ZONE 17		Model Met Data Period
		(µg/m^3)	(µg/m^3)	X	Y	[mmddyyyy]
PM10	Annual	0.2	0.006280	468692	3468715	1992
	24-Hour	0.3	0.060670	468692	3468715	08191991
NOx	Annual	0.1	0.008920	468692	3468715	1992

* Highest value.

Table 6-8: Project Impacts Vs. Significance Levels (St. Marks Class I Area)

Criteria Pollutant	Averaging Period	Significance Level	Maximum Predicted Concentration*	Receptor Location UTM ZONE 17		Model Met Data Period
		(µg/m^3)	(µg/m^3)	X	Y	[mmddyyyy]
PM10	Annual	0.2	0.000179	212993	3337589	2002
	24-Hour	0.3	0.0055	212993	3337589	01282002
NOx	Annual	0.1	0.000202	212993	3337589	2002

* Highest value.

Table 6-9: Project Impacts Vs. Significance Levels (Chassahowitzka Class I Area)

Criteria Pollutant	Averaging Period	Significance Level	Maximum Predicted Concentration*	Receptor Location UTM ZONE 17		Model Met Data Period
		(µg/m^3)	(µg/m^3)	X	Y	[mmddyyyy]
PM10	Annual	0.2	0.000088	335260	3183589	2002
	24-Hour	0.3	0.0059	338515	3183543	10282002
NOx	Annual	0.1	0.000050	338515	3183543	2001

* Highest value.

Table 6-10: Project Impacts Vs. Significance Levels (Cape Romain Class I Area)

Criteria Pollutant	Averaging Period	Significance Level	Maximum Predicted Concentration*	Receptor Location UTM ZONE 17		Model Met Data Period
		(µg/m^3)	(µg/m^3)	X	Y	[mmddyyyy]
PM10	Annual	0.2	0.000462	626669	3639438	2003
	24-Hour	0.3	0.0073	629511	3649517	01302003
NOx	Annual	0.1	0.000430	626669	3639438	2003

* Highest value.

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

Class I Air Quality Related Values (AQRV)

AQRVs require two types of modeling analyses: Visibility and Deposition of Nitrogen and Sulfur. Both assessments were undertaken using the CALPUFF model and the POSTUTIL and CALPOST post-processors. In addition, as requested by the FLM for the visibility analysis, the CALPOST post-processor was set to use the Method 2 calculation, with a maximum relative humidity of 95%.

An exception to this procedure was the visibility analysis at the Wolf Island NWR, which being located at only 23 kilometers of the permitted facility, required the use of the VISCREEN model. Results for Visibility and Deposition analyses are shown in Tables 6-11 to 6-13.

Table 6-11: Class I Visibility Impacts

CLASS I AREA	Maximum % of Change in Light Extinction*	# of Days with % of Change > 5 *	Year
Okefenokee	2.0	0	2003
St. Marks	0.52	0	2002
Chassahowitzka	0.37	0	2002
Cape Romain	0.57	0	2003

* The percentage of change in light extinction is a measure of the decrease in natural background visibility. The threshold to determine if visibility impairment can be expected is 5% of change in natural background light extinction. With values below 5%, it is expected that visibility impacts be negligible.

Table 6-12: Class I Visibility Impacts At Wolf Island NWR With VISCREEN Level II

WOLF ISLAND NWR	Color Difference Index (Delta E)		Plume Contrast	
	Maximum Predicted Value	Screening Threshold	Maximum Predicted Value	Screening Threshold
Sky Background	0.556	2.0	0.011	0.05
Terrain Background	2.072	2.0	0.012	0.05

Table 6-13: Class I Deposition Of Nitrogen And Sulfur

Class I Area	DAT (kg/ha/yr) *	Maximum Nitrogen Deposition (kg/ha/yr)	Maximum Sulfur Deposition (kg/ha/yr)	Year
Okefenokee	0.01	0.0015	0.0010	2002
St. Marks	0.01	0.00020	0.00014	2002
Chassahowitzka	0.01	0.000063	0.000058	2002
Cape Romain	0.01	0.00028	0.00026	2003

* The Deposition Assessment Threshold (DAT) is the same for sulfur and nitrogen.

Predicted deposition values for Nitrogen and Sulfur are all below the Deposition Assessment Threshold (DAT), so it can be concluded that no negative impacts can be expected. Regarding visibility, for Okefenokee, Saint Marks, Chassahowitzka, and Cape Romain, the predicted impacts are below the 5% threshold and therefore no visibility impairment can be expected.

For Wolf Island however, using a different methodology as required in near-field analyses, the maximum predicted value of color difference index exceeds the screening threshold when assessed against terrain background. The maximum plume contrast values were all below the corresponding threshold.

Given such result, the FLM requested the applicant to follow the next step in the visibility analysis as indicated in the EPA guidance document "Workbook for Plume Visual Impact Screening and Analysis". This next step is to submit a VISCREEN level III analysis.

However, it should be noted that Wolf Island and the nearby terrain is a flat area, with no elevations that could be considered as terrain background for the visibility analysis. Based on this fact, the applicant requested that the VISCREEN results assessed against terrain background not be included in this case since they should not be applicable for this particular Class I area.

The applicant submitted additional documentation supporting their request and upon its review, GA EPD issued a letter to the FLM expressing our agreement with the applicant's position and requesting them to reconsider their decision (see the attached addendum to the permit application and letter to the FLM). Since no response was received from the Fish and Wildlife Service, it is assumed that they have no objection to the decision of not applying the terrain background scenario to this particular situation, in which case, it could be concluded that no visibility impairment can be expected at Wolf Island due to this project.

7.0 ADDITIONAL IMPACT ANALYSES

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

Soils and Vegetation

With regard to the impacts on soils and vegetation, the criteria to assess air pollution impacts are the standards contained in the EPA document *"A Screening Procedure for the impacts of Air Pollution Sources on Plants, Soils, and Animals"*. The analysis presented by the applicant followed different guidelines and therefore additional AERMOD modeling would have been required had the facility exceeded the Class II significance levels. However, considering that all pollutants subject to PSD review, when modeled, did not exceed the significant impact levels, it can be concluded that their impacts on soils and vegetation would be negligible.

Growth

The growth analysis is a projection of the commercial, industrial, and residential growth that may be expected to occur as direct result of the implementation of the proposed project. In the case of Live Oaks Power Plant, the facility is expected to employ a total of 25 operational workers on a permanent basis once the project is built, which represents a very small fraction of the population already existing in the area. In addition, the facility will be located at an existing industrial park, and no additional commercial or industrial infrastructure will be required. Therefore, no related industrial, commercial or residential growth is expected to accompany this project, hence no growth-related air pollution impacts can be foreseen.

Visibility

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

Another form of visibility impairment in the form of plume blight occurs when particles and light-absorbing gases are confined to a single elevated haze layer or coherent plume. Plume blight, 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 "sensitive receptors" within the SIA of the Live Oaks Power Plant. Since the emissions from the Live Oaks Power Plant did not exceed the significant impact levels, there is no significant impact area, and consequently no sensitive receptors can be defined, and no further Class II visibility analysis is required.

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 pipeline quality natural gas, and ultra low sulfur diesel fuel 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.

Eleven of the TAPs that will be discharged to the atmosphere are hazardous air pollutants (HAPs) and are shown in Table 7-1. These eleven HAPs all have emission factors in AP-42 for combustion turbines and were chosen for modeling based on being on this list. Several other TAPs are emitted during natural gas combustion, and have emission factors in AP-42 for boilers, but their emission levels are significantly less. Most of the TAPs will be 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 highest or "worst-case" 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 (Maximum Ground Level Concentrations or MGLCs) were thus calculated for each HAP by multiplying the worst-case 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 input meteorological surface data for surface air was collected from station 03822 in Savannah, GA, and upper air data was collected from station 13880 in Charleston, SC. These data correspond to the 5-year period from 1990 – 1994. All meteorological data had been previously pre-processed to be suitable for use in the dispersion model. The met year listed in table 7.1 is the input year that resulted in worse case emissions. The annual and 24-hour modeled values were compared directly to their corresponding AACs, 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. A comparison shows that all MGLCs assessed were found to be less than their respective AACs, as presented in Table 7-1 below. The Ambient Impact Analysis is located in section 6.3.7 of the application.

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. Live Oaks Power Plant referenced the resources previously detailed to determine the long-term (i.e., annual average) and short-term AACs (i.e., 24-hour or 15-minute). The AACs were verified by the Division.

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 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 AAC. Due to the likelihood that this screening would result in the need for further analysis for most TAPs, the screening step was skipped and the analyses were initiated with the secondary screening technique.

Table 7-1: Air Toxics Assessment

Pollutant	Averaging Period	AAC (ug/m3)	Met. Data Year	MGLC	
				(ug/m3)	(% of AAC)
1,3-Butadiene	15 min	1100	1993	5.57E-04	0.000%
	Annual	0.040	1992	1.03E-05	0.026%
Acetaldehyde	15 min	4500	1993	5.19E-02	0.001%
	Annual	5.000	1992	9.62E-04	0.019%
Acrolein	15 min	23	1993	8.30E-03	0.036%
	Annual	0.020	1992	1.54E-04	0.770%
Ammonia	15 min	2400	1993	8.93E-00	0.372%
	Annual	100.0	1992	1.66E-01	0.166%
Benzene	15 min	1600	1993	1.60E-02	0.000%
	Annual	0.120	1992	2.97E-04	0.247%
Ethylbenzene	15 min	54300	1993	4.15E-02	0.004%
	Annual	1000	1992	7.70E-04	1.925%
Formaldehyde	15 min	245.0	1993	2.96E-01	0.121%
	Annual	0.077	1992	5.49E-03	0.712%
Naphthalene	15 min	7500	1993	1.81E-03	0.000%
	Annual	3	1992	3.37E-05	0.001%
Sulfuric acid mist	15 min	300	1993	3.58E-01	0.119%
	24 Hours	2.40	1993	8.53E-02	3.555%
Toulene	15 min	113000	1993	1.69E-01	0.000%
	Annual	400	1992	3.14E-03	0.001%
Xylene	15 min	65500	1993	8.30E-02	0.000%
	Annual	100	1992	1.54E-03	0.002%

8.0 EXPLANATION OF DRAFT PERMIT CONDITIONS

The permit requirements for this proposed facility are included in draft Permit No. 4911-127-0075-P-02-0. Live Oaks Company, LLC proposes to construct and operate a combustion turbine combined-cycle power plant. The proposed project will be located in Sterling Georgia, and will generate approximately 600 megawatts of power. The single power block will be fired exclusively with natural gas, and will consist of two combustion turbines, each with a nominal power output of 200 MW; two heat recovery steam generators (HRSGs) with supplemental firing; and one steam turbine with a nominal output of 200 MW. Additional equipment includes a 600 kW emergency generator, a 310 hp emergency firewater pump, two fuel heaters, and a 10-cell mechanical draft cooling tower.

Section 1.0: General Requirements

Condition 1.1 states that the facility must operate the equipment in a manner consistent with good air pollution control practices to minimize emissions at all times.

Condition 1.2 states that the facility must not do anything to conceal an emission that would violate an applicable emission standard.

Condition 1.3 states that the facility must submit an air permit application prior to any modifications to the facility.

Condition 1.4 states that records required by the permit are to be retained for 5 years.

Condition 1.5 states that if a permit condition conflicts with another permit condition for any reason that the most stringent condition shall prevail.

Condition 1.6 states that the facility must comply with 40 CFR 60 Subpart KKKK requirements for stationary combustion turbines CT1, and CT2.

Condition 1.7 states that the facility must comply with the acid rain regulations in 40 CFR Parts 72, 73, 75, and 77.

Condition 1.8 states that the facility must comply with 40 CFR 60 Subpart Dc requirements for small industrial-commercial-institutional steam generating units.

Condition 1.9 states that the facility must comply with 40 CFR 60 Subpart IIII requirements for stationary compression ignition internal combustion engines.

Section 2.0: Allowable Emissions

Conditions 2.1 and 2.2 state that the turbine blocks and heat recovery steam generators must be constructed within a specified reasonable time frame or the permit becomes null and void for un-constructed units per PSD regulations.

Condition 2.3 states that the facility must install and operate selective catalytic reduction control equipment as BACT for NO_X on all of the combustion turbines and duct burners.

Condition 2.4 states that the facility must install and operate catalytic oxidation control equipment as BACT for CO and VOC on all of the combustion turbines and duct burners.

Condition 2.5 sets rolling annual emission limits for NO_X at 87 tons, and CO at 208 tons from each combined turbine and duct burner stack that apply at all times, including startup, shutdown, and malfunction.

Condition 2.6 sets the NO_X emission limit at 15 ppmvd corrected to 15% oxygen at all times excluding startup and shutdown, on a 30-day rolling average, per 40 CFR 60 Subpart KKKK.

Condition 2.7 sets the SO_2 emission limit at 0.9 lbs/MW-hr, per 40 CFR 60 Subpart KKKK.

Conditions 2.8 and 2.9 state that the facility must only burn pipeline quality natural gas as defined in 40 CFR Part 72 as BACT for PM_{10}, and as BACT avoidance for SO_2 and SAM in the combustion turbines, duct burners, and fuel heater.

Condition 2.10 states that the fuel burned in the emergency generator and firewater pump must meet the specifications for ultra low diesel fuel with sulfur content less than or equal to 15 ppm.

Condition 2.11 limits pollutant emissions from each combustion turbine, and its paired duct burner during normal operation, on a 3-hour rolling average.

2.11a limits NO_X to 2.5 ppm corrected to 15% oxygen as BACT, subsuming 40 CFR 60 Subpart KKKK limit
2.11b limits CO to 3.2 ppmvd corrected to 15% oxygen while the duct burner is being fired as BACT
2.11c limits CO to 2.0 ppmvd corrected to 15% oxygen while the duct burner is not being fired as BACT
2.11d limits VOC to 2.0 ppm corrected to 15% oxygen as BACT

Condition 2.12 limits the hours that the emergency generator and firewater pump are allowed to run in any 12 consecutive months.

Condition 2.13 defines the meaning of cold start, warm start, hot start, and shutdown, for the purposes of the permit.

Condition 2.14 requires the Permittee to submit a Title V operating permit application within 12 months of commencing commercial operation.

Condition 2.15 limits opacity from the combustion turbine and duct burner stacks to 40% opacity per Georgia Rule (b).

Section 3: Fugitive Emissions

Condition 3.1 states that the Permittee must take all reasonable precautions to prevent fugitive dust emissions.

Section 4: Process & Control Equipment

Not applicable

Section 5: Monitoring

Condition 5.1 states that all continuous monitoring equipment required by the permit must be in continuous operation, and that all repairs and maintenance must be done expediently to maintain its operation.

Condition 5.2 requires the installation and certification of NO_X and CO continuous emissions monitoring systems (CEMS) for each combined combustion turbine and duct burner stack. It also requires that these CEMS be used to determine the average emission rate of NO_x and CO from each stack for each hour of operation, both in terms of pound pollutant per million Btu heat input (lb/MMBtu) and parts per million (ppm).

Condition 5.3 requires monitoring of the amount of natural gas burned in the combustion turbines, duct burners, and fuel heater, as well as the monthly total hours of operation of the emergency generator and firewater pump.

Condition 5.4 requires semi-annual verification of the sulfur content of the natural gas burned at the plant by obtaining and submitting to the Division a current valid purchase contract, tariff sheet, or transportation contract from the gas supplier.

Condition 5.5 requires application of Appendix F, Procedure 1 (40 CFR Part 60, Appendix F) to the CO CEMS installed on the combustion turbine stacks.

Section 6: Performance Testing

Condition 6.1 states that the Permittee must conduct a performance test upon request by the Division, and sets the requirements for such tests.

Condition 6.2 describes the methods that must be used when performance and compliance tests are performed to show compliance with the limits in Section 2 of the permit.

Condition 6.3 states the requirements for initial performance tests that must be done within 180 days after initial startup.

Section 7: Notification, Reporting, and Record Keeping Requirements

Condition 7.1 requires the Permittee to retain monthly gas usage records.

Condition 7.2 requires the Permittee to record the operating hours of the emergency firewater pump and emergency generator.

Condition 7.3 requires the Permittee to use the hourly emission rates determined per Condition 5.2a to calculate and record the average NO_x emission rate for each hour, in terms of pounds per hour (lb/hr), in accordance with Federal Acid Rain Rules.

Condition 7.4 requires the Permittee to calculate and record a 3-hour rolling NO_x emission rate (in ppm at 15% oxygen) to demonstrate compliance with the NO_x BACT limit in Condition 2.11a. Also, a 30-day rolling NO_x emission rates must be calculated to demonstrate compliance with 40 CFR 60 Subpart KKKK.

Conditions 7.5 and 7.6 require the Permittee to use the hourly NO_x emission rates, determined per Condition 7.3, to calculate monthly and 12 month rolling total NO_x emission rates to demonstrate compliance with Condition 2.5a.

Condition 7.7 requires the Permittee to use the hourly emission rates determined per Condition 5.2b to calculate and record the average CO emission rate for each hour, in terms of pounds per hour (lb/hr), using the same method as the Federal Acid Rain Rules for NO_x.

Condition 7.8 requires the Permittee to use the hourly emission rates determined per Condition 5.2b to calculate and record a three-hour average CO emission rate (in ppm at 15% oxygen) to demonstrate compliance with the CO BACT limit in Conditions 2.11b and c.

Conditions 7.9 and 7.10 require the Permittee to calculate and record monthly and rolling twelve-month total CO emission rates to demonstrate compliance with Condition 2.5b.

Condition 7.11 requires the Permittee to record startup and shutdown information.

Condition 7.12 requires the Permittee to monitor the sulfur content of the diesel fuel burned in the emergency generator and firewater pump.

Condition 7.13 states that the Permittee must maintain records of all measurements, monitoring devices, and performance testing.

Condition 7.14 requires the Permittee to submit notifications when they start construction, startup the turbines, and certify that each system was constructed in accordance with this permit.

Condition 7.15 requires the Permittee to notify the Division in writing within 7 days if they have a malfunction, or process breakdown that results in excess emissions.

Condition 7.16 outlines the information that must be submitted in the semi-annual report that must be submitted to the Division.

Condition 7.17 defines excess emissions, exceedances, and excursions for reporting purposes.

Condition 7.18 specifies the parameters that must be reported semi-annually.

Condition 7.19 outlines the reporting requirements of CFR 60 Subpart IIII for the Emergency Generator.

Condition 7.20 outlines the reporting requirements of 40 CFR 60 Subpart IIII for the Emergency Fire Water Pump.

Section 8:

Condition 8.1 states that the Division reserves the right to amend the provisions in the permit within the authority established in the Georgia Air Act.

Condition 8.2 states that the Permittee must pay an annual permit fee according to the applicable procedures.

APPENDIX A

Draft PSD Permit – Live Oaks Company, LLC
Live Oaks Power Plant
Sterling (Glynn County), Georgia

APPENDIX B

Live Oaks Power Plant PSD Permit Application and Supporting Data

Contents Include:

1. PSD Permit Application No. 18569, dated November 18, 2008

2. Updates to PSD Permit Application No. 18569

- Cost Analysis Tables for SCR, and Oxidation Catalyst control systems
- Startup/Shutdown Detailed Information
- Page 1 of Table A-2, Page 2 of Table A-4, left out of original printed application
- Application Addendum for Visibility Analysis

3. Derivation of Emission Rates, with summary of plant emissions.

SCR COST ANALYSIS

OXIDATION CATALYST COST ANALYSIS

DERIVATION OF EMISSION RATES

Steady State Emissions for Criteria and Hazardous Air Pollutants from Combustion Turbines and Duct Burners at Live Oaks Power Plant

Below are the computations of the steady state emission rates of criteria air pollutants from the Live Oaks Power Plant with best available control technology (BACT). The BACT determinations for NO_X, CO, and VOC are expressed as concentrations. The BACT determinations for lead, SO_2 and PM_{10} are expressed as lb/hr. A concentration is converted to a mass emission rate as follows:

$$E = FC[20.9/(20.9\text{-}\%O_2d]$$

where E = pollutant emission rate in lb/MMBtu.
C = pollutant concentration in lb/dscf.
$\%O_2d$ = % oxygen expressed on a volume basis.
F = dry flue gas factor, or F factor = 8710 dscf/MMBtu for natural gas.

The conversion from C in lb/dscf to C in ppm is accomplished by multiplying C by 2.59×10^{-9} and then by the pollutant molecular weight.

The maximum heat input rate for each turbine and its paired duct burner combined is 2334MMBtu @ 59°F

Total Emissions per CT/HRSG

	Emissions ppmvd,@ 15% O2	Steady State Emissions lb/hr - Max Heat Rate	Startup/Shutdown Additional Emissions – (TPY)	CT Only Emissions without Duct Firing 2546 hrs/yr (TPY)	CT+DB Emissions with Duct Firing 4000 hrs/yr (TPY)	Emissions Total per CT/HRSG (TPY)
NO_X	2.5	21.45	21.54	23.28	42.90	87.72
CO	3.2/2.0	16.72	163.27	11.34	33.44	208.05
VOC	2.0	5.98	22.87	6.50	11.97	41.33
SO_2	-	3.36	0.69	3.81	7.02	11.52
PM/PM_{10}	-	12.60	2.48	13.68	25.21	41.37
H_2SO_4	-	0.73	0.13	0.74	1.52	2.39

Startup/Shutdown Emissions Detail per CT/HRSG

	Cold Starts	Warm Starts	Hot Starts	Shutdowns	
NO_X - lbs/event	446	254	119	24	
CO - lbs/event	3490	1837	934	185	
VOC - lbs/event	397	247	130	38	
Minutes per event	215	125	64	41	
Number of events	18	63	119	200	
Total Hours	65	131	129	137	Total (TPY)
NO_X - lbs/year	8032	16015	14185	4840	21.5
CO - lbs/year	62815	115712	111098	36920	163.3
VOC - lbs/year	7144	15574	15494	7520	22.9

HAP Emissions per CT/HRSG – 8760 hrs/steady state w/4000 hrs duct firing, from Table A-5 in application.

Hazardous Air Pollutants	CT Only Emissions lb/hr	CT Only Emissions tpy	DB Emissions lb/hr	DB Emissions tpy – 4000 hrs/yr	CT+DB Emissions lb/hr	Total per CT/HRSG Emissions - tpy
Acetaldehyde	0.08	0.35	-	-	0.08	0.4
Acrolein	0.013	0.056	-	-	0.013	0.1
Benzene	0.024	0.1	0.00065	0.0013	0.025	0.1
Ethyl Benzene	0.064	0.28	-	-	0.064	0.3
Formaldehyde	0.429	1.9	0.023	0.0460	0.45	1.9
Propylene Oxide	0.058	0.25	-	-	0.058	0.3
Toluene	0.26	1.1	0.001	0.0021	0.26	1.1
Xylene	0.13	0.56	-		0.13	0.6
Total HAPs	1.06	4.60	-	-	1.08	4.6

Estimated Plant Emissions after application of BACT (tons/year)

	Total for both CT/HRSGs	Diesel Firewater Pump	Diesel Emergency Generator	Fuel Heaters	Cooling Tower	Plant Emissions
NO_X	175.44	0.51	2.12	5.17	-	182.2
CO	416.10	0.44	1.16	3.92	-	421.6
VOC	82.66	0.21	0.55	0.22	-	83.6
SO_2	23.04	0.03	0.08	0.05	-	23.2
PM/PM_{10}	82.73	0.03	0.07	0.16	5.3	88.3
H_2SO_4	4.79	-	-	-	-	4.8
Acetaldehyde	0.70	-	-	-	-	0.7
Acrolein	0.112	-	-	-	-	0.1
Benzene	0.22	-	-	-	-	0.2
Ethyl Benzene	0.56	-	-	-	-	0.6
Formaldehyde	3.8	-	-	-	-	3.8
Propylene Oxide	0.50	-	-	-	-	0.5
Toluene	2.2	-	-	-	-	2.2
Xylene	0.112	-	-	-	-	0.1
Total HAPs	9.22	-	-	-	-	9.2

APPENDIX C

EPD’S PSD Dispersion Modeling and Air Toxics Assessment Review