Prevention of Significant Air Quality Deterioration Review
Of the Monroe Power Company
Effingham County Power Facility
To be located in Effingham County, Georgia

PRELIMINARY DETERMINATION
SIP Permit Application No. 12727
August 2001

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

Stationary Source Permitting Program (SSPP)	Planning & Support Program
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SUMMARY I

SUMMARY

The Environmental Protection Division (EPD) has reviewed the Monroe Power Company application (application No. 12727) to construct and operate an electrical generation facility with a nominal electrical generating capacity of 370 MW in *Simple-Cycle* operation and 525 MW in *Combined-Cycle* operation located in Effingham County, near the City of Rincon, Georgia. For the purpose of this application, this facility will be referred to as the "Effingham County Power Facility (ECPF)." The facility will initially consist of two 1,734 MMBtu/hr General Electric (GE) 7FA *simple-cycle* combustion turbine generators burning only natural gas, one 2.06 MMBtu per hour diesel-fired water pump, one 8.75 MMBtu per hour natural gas fired fuel preheater and ancillary equipment and is planned to commence operation in June of 2002. The facility will be converted to a baseload *combined cycle* power plant by adding two heat recovery steam generators (with no duct firing) with SCR for NO_x pollution control, one 17 MMBtu per hour natural gas fired auxiliary boiler, and one cooling tower. C*ombined-Cycle* operation is expected to begin in June of 2003.

The estimated potential emissions of regulated pollutants from the facility for *Simple-Cycle* based on 2,672 hours per year for two *Simple-Cycle* combustion turbines are as follows: Particulate Matter with an aerodynamic diameter less than 10 microns (PM_{10}) = 48.4 tons per year (tpy); Total Suspended Particulate (TSP) = 48.4 tpy; Nitrogen Oxides (NO_x) = 227.4 tpy; Carbon Monoxide (CO) = 85.1 tpy; Sulfur Dioxide (SO_2) = 17.6 tpy; Ozone (Volatile Organic Compounds) = 8.3 tpy, Lead (Pb) = 1.15E-05 tpy; Sulfuric Acid Mist (H_2SO_4) = 0.2 tpy.

The estimated potential emissions of regulated pollutants from the facility for *Combined-Cycle* based on 8,760 hours per year for two combined-cycle combustion turbines are as follows: Particulate Matter with an aerodynamic diameter less than 10 microns (PM_{10}) = 189.8 tpy; Total Suspended Particulate (TSP) = 259.1 tpy; Nitrogen Oxides (NO_x) = 223.8 tpy; Carbon Monoxide (CO) = 294.4 tpy; Sulfur Dioxide (SO_2) = 58.2 tpy; Ozone (Volatile Organic Compounds) = 28.5 tpy, Lead (Pb) = 2.9E-05 tpy; Sulfuric Acid Mist (H_2SO_4) = 0.5 tpy.

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

The EPD review of the data submitted by ECPF for proposed combustion turbine facility indicates that compliance with all applicable State and Federal air quality regulations will be achieved. It is the Preliminary Determination of EPD that the proposal provides for the application of best available control technology (BACT) for the control of NO_x, CO, SO_2, and PM/PM_{10} as required by Federal PSD regulation 40 CFR 52.21(j).

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

The Preliminary Determination indicates that an Air Quality Permit should be issued to Monroe Power Company for the construction and operation of the *Simple* and *Combined-Cycle* generators. Various conditions will be made a part of the permit to construct and operate in order to insure and confirm compliance with all applicable regulations.

1.0 INTRODUCTION

1.1 PSD Requirements

The regulations for Prevention of Significant Air Quality Deterioration (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 for any new or modified source which belongs to one of 28 specific source categories having potential emissions of 100 tons per year or more of any regulated pollutant, or all other sources having potential emissions of 250 tons per year or more of any regulated pollutant; or modification of a major stationary source which results in a significant net emission increase of any regulated pollutant.

The PSD regulations require that any major stationary source or major modification subject to the regulations meet the following requirements: 1) Application of Best Available Control Technology (BACT) for each regulated pollutant that would be emitted in significant amounts; 2) Analysis of the ambient air impact; 3) Analysis of the impact on soils, vegetation, and visibility; 4) Analysis of the impact on Class I areas; and 5) Public notification of the proposed operation in a newspaper of general circulation.

1.2 Proposal

On December 21, 2000, Monroe Power Company submitted an application for an air quality permit to construct and operate an electrical generation facility with a nominal electrical generating capacity, upon completion, of 525 megawatts (MW), located at Effingham County (ECPF), near the City of Rincon, Georgia (3 miles south-southeast of Rincon and approximately 20 miles north-northwest of Savannah). The ECPF will be operated as a base load plant. The proposed site is located in a sparsely populated mainly forested area and is approximately 300-acre. The terrain surrounding the facility consists of rolling hills and the proposed site is a remote and large site.

The ECPF proposed a 17 MMBtu/hr auxiliary boiler AB1 that will be installed as part of this project and will combust natural gas only. However, in contrast with the turbines, the auxiliary boiler is used only during *Combined-Cycle* operations to provide necessary steam augmentation to the heat recovery steam generators and steam turbines. The facility proposed to operate the boiler AB1 only 2,500 hours per year. During *Combined-Cycle* operations, the facility proposed to utilize one Cooling Tower CT1 with ten cells. The cooling tower function will be to provide cooling water to the condensing steam turbine during *Combined-Cycle* operations. The tower will be a mechanical draft counter-flow design. The proposed diesel fire pump DWP1 will be used for emergency purposes in case of fire and will be rated at 235 BHP (2.06 MMBtu per hour). The fire pump will be limited to 500 hours per year operation due to the non-routine nature of operation. The proposed 8.75 MMBtu per hour natural gas fired preheater PF1 will operate a maximum 4,000 hours per year during *Simple-Cycle* operation and 8,760 hours per year during *Combined-Cycle* operation.

The ECPF also proposed two GE 7FA combustion turbines (CTG1 and CTG2) that will fire on natural gas exclusively for both *Simple* and *Combined-Cycle* operations. At full load *Simple-Cycle* operations, the facility proposed to control nitrogen oxide emissions from each CTG to a level of 12.0 ppmvd corrected to

15 percent O_2 using dry low NO_x (DLN) technology when firing natural gas. At full load *Combined-Cycle* operations, the facility proposed NO_x emissions from each CTG will be controlled to a level of 3.5 ppmvd corrected to 15 percent O2 using a combination of DLN technology and Selective Catalytic Reduction (SCR).

1.3 Applicability

The proposed facility is classified as a major source in both *Simple Cycle* and *Combined-Cycle* operation under the PSD regulations. Since the facility is planned to be a combined cycle operation upon completion, it is being treated as one of the 28 source categories defined in the definition of major source under 40 CFR 52.21(b) – *a fossil fuel-fired steam electric plant with a heat input of more than 250 million Btu per hour*. Once a new source or modification is subject to PSD, the PSD requirements apply to every air pollutant subject to regulation under the Act that is emitted in "significant quantities."

1.4 Potential Emissions

The potential to emit of air toxics for *Simple Cycle* and *Combined-Cycle* are listed in Appendix table A-3 and A-4 of the application, respectively. Potential emissions, for the NO_x, CO, VOC, SO2, and PM/PM_{10} are based on vendor supplied hourly emission rates. The lead (Pb) emissions were based on AP-42 emission factors (EPA 1998, and 2000). The potential to emit of regulated air pollutants under this proposal are illustrated in Table 1.

Table 1. Emissions Summary for Facility

Pollutant	Potential To Emit (TPY) for simple cycle/combined cycle	PSD Significant Emissions Level	Is BACT Required?
NO_x	Simple: 227.4 Combined: 223.8	40	YES
CO	Simple: 85.1 Combined: 294.4	100	YES
VOC	Simple: 8.3 Combined: 28.5	40	NO
SO_2	Simple: 17.6 Combined: 58.2	40	YES
TSP	Simple: 48.4 Combined: 259.1	25	YES
PM_{10}	Simple: 48.4 Combined: 189.8	15	YES
Lead	Simple: 1.15E-05 Combined: 2.9E-05	0.60	NO
Sulfuric Acid Mist	Simple: 0.2 Combined: 0.5	7.0	NO

1.5 Preliminary Determination

Through its new source review procedure, EPD has evaluated the ECPF proposal for compliance with all applicable State and Federal requirements. The findings of EPD have been assembled in this Preliminary Determination. ECPF's application and supporting data are included in attached **Appendix A**.

2.0 APPLICABLE RULES AND REGULATIONS

In addition to the PSD regulations, the following Federal and State regulations and their potential applicability to the proposed facility are discussed.

2.1 New Source Performance Standards (NSPS)

The NSPS are a group of national emission standards for both criteria and other designated pollutants applicable to new, modified or reconstructed source (40 CFR Part 60). NSPS regulations are incorporated into Georgia Air Quality Rules by reference, Chapter 391-3-1-.02(8). The specific requirements of NSPS applicable to the ECPF are discussed below:

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

Applicability: New Source Performance Standards (NSPS) in 40 CFR Part 60 requires new sources to control emissions to the level achievable by the best-demonstrated technology specified in the applicable provisions. Subpart GG (40 CFR 60.330 et seq.) applies to stationary gas turbines with heat input at peak load of equal to or greater than 10 MMBtu per year, which are constructed after October 3, 1977. The turbines to be located at the ECPF will be subject to the provisions of Subpart GG. The facility will be subject to the standard for nitrogen oxides in 40 CFR 60.332 and standards for sulfur dioxide in 40 CFR 60.333 as well as the appropriate monitoring and test methods/procedures contained in Subpart GG.

Emission Standard: The facility is subject to the standard for nitrogen oxides in 40 CFR 60.332 and standards for sulfur dioxide in 40 CFR 60.333 as well as the appropriate monitoring and test methods/procedures contained in Subpart GG. The allowable NO_x emission rate is specified by the following formula [40 CFR 60.332(a)(1)] because each CT has a heat input rating greater than 100 MMBtu/hr:

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

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

Simple-Cycle Mode

$Y_{100\%\ load\ (max)}$ = 9.9 KJ/W-hr, $Y_{50\%\ load\ (max)}$ = 12.8 KJ/W-hr, F = 0.0

NO_x std $_{100\%\ load\ (max)}$ = 0.0109 % vd or 109 ppmvd
NO_x std $_{50\%\ load\ (max)}$ = 0.0084 % vd or 84 ppmvd

Combined-Cycle Mode

$Y_{100\%\ load\ (max)}$ = 9.6 KJ/W-hr, $Y_{50\%\ load\ (max)}$ = 12.4 KJ/W-hr, F = 0.0

NO_x std $_{100\%\ load\ (max)}$ = 0.0113 % vd or 113 ppmvd
NO_x std $_{50\%\ load\ (max)}$ = 0.0087 % vd or 87 ppmvd

The allowable fuel sulfur content is 0.8 percent by weight in accordance with 40 CFR 60.333(b).

Compliance Demonstration: Compliance is demonstrated with an initial performance test using Method 20 and thereafter by monitoring the water-to-fuel injection ratio and reporting excess emissions based on that ratio. Where units do not employ water injection, EPA has asked that sources propose an alternative method and, where requested, has approved use of NO_x CEMS to identify and report excess emissions

Federal Rule 40 CFR 60, Subpart Dc "Standard of Performance for Small Industrial Commercial-Institutional Steam Generating Units"

Applicability: Subpart Dc (40 CFR 60.40c eq seq.) affects facilities which are steam generating units with a maximum design heat input capacity equal to or greater than 10 MMBtu per year but less than or equal to 100 MMBtu per year and for which construction is commenced after June 9, 1989. During *Combined Cycle* operation, a 17 MMBtu per year auxiliary AB1 will be located at the ECPF and will be subject to the record keeping and reporting requirements pursuant to 40 CFR 60.48c(a).

Emission Standard: NSPS Dc does not define any emission standard for the fuel gas heater because it is exclusively fired with natural gas.

Compliance Demonstration: The facility is subject to the reporting and record keeping requirement of 40 CFR 60.48c(g). This portion of NSPS Dc requires the recording of the amount of fuel combusted during each day. In this case, this requirement can be altered, by EPA, pursuant to authority in 40 CFR 60.13(i). EPA notes, "Since there are no applicable emission standards for natural gas combustion in Subpart Dc, the amount of gas burned each day has no bearing on the compliance status of the boiler."[1] In the case of natural gas combustion, EPA Region 4 has approved an alternative fuel usage monthly record keeping frequency.

2.2 National Emission Standards for Hazardous Air Pollutants (NESHAP)/Case-by-Case Maximum Achievable Control Technology (MACT) Analysis

The National Emission Standards for Hazardous Air Pollutants (NESHAPs) regulations were promulgated under Section 112 of the Clean Air Act in 1977 to identify and regulate specific listed substances including asbestos, benzene, beryllium, inorganic arsenic, mercury, radionuclides, and vinyl chloride. These original NESHAP regulations are included in 40 CFR Part 61.

In 1990, the NESHAPs program was amended to include designation of 189 substances as Hazardous Air Pollutants (HAPs), identification of source categories subject to control of HAPs, and establishment of control technology standards for HAPs. These amended NESHAP standards, included in 40 CFR Part 63, are based on Maximum Achievable Control Technology (MACT). State of Georgia has adopted by reference in 391-3-1-.02(9) the NESHAP standards set forth in 40 CFR Parts 61 and 63 and Section 112(g) became effective in Georgia on June 30, 1998.

Stationary combustion turbines, including *Combined Cycle* systems, were included on the category list of the Clean Air Act Section 112(c)(5). However,

[1] See Alternative Fuel Usage Record keeping Frequency Proposed for Boiler at Shaw Industries, U.S. EPA Region IV, August 14, 1996.

USEPA has not yet promulgated a NESHAP for the combustion turbine source category. Therefore, Section 112(g) of the Clean Air Act applies to the ECPF. In accordance with 112(g), the ECPF must complete a case-by-case MACT determination if it meets the criteria for a major source. A major source for HAP emissions is a source with emissions greater than 10 tons per year of any single HAP or 25 tons per year of combined HAPs (see Appendix Table A-3 & A-4 of the application).

EPD recognizes that EPA's development of their CT database, and the work of numerous other turbine and utility organizations, is extremely promising in generating credible HAP emissions data from gas-fired turbines. However, the application indicated that the proposed facility will not be subject to MACT requirements for combustion turbines since the primary HAP emitted by the CTGs is "formaldehyde" and emission is 2.103 tpy for *Simple Cycle* and 8.648 tpy for *Combined Cycle* operation (emission factor are based on the formaldehyde emission factor of 1.1×10^{-4} lbs per MMBtu obtained from California Air Resource Board emission inventory). It is our position that the data submitted by the ECPF does not indicate that the proposed facility would emit individual HAP emissions on the order of 10 tpy or higher or would emit total HAPs greater than 25 tpy (see Appendix A of the application for HAPs calculations).

EPD considered whether the exclusion offered to "electric utility steam generating units" applies in this case. Based on EPA's Interpretative Rule published in the Federal Register on May 25, 2000 [65 FR 34010], the *Simple Cycle* turbine in a *Combined Cycle* system is subject to 112(g) provided it also meets the definition of a major source under Part 63.[2] The exclusion only applies to the emissions from the HRSGs and the steam generators.

2.3 Acid Rain Program (40 CFR 72 through 78)

Applicability: Title IV of the 1990 Clean Air Act Amendment created a program to control emissions of Sulfur Oxides and Nitrogen Oxides to reduce acid precipitation. The standards are promulgated in 40 CFR Parts 72 through 78. State of Georgia has adopted standards set forth in 40 CFR Parts 72 through 78 by reference in 391-3-1-.13. The Acid Rain Regulations apply to the ECPF because each combustion turbine has a nameplate capacity greater than $25MW_e$ and they are to supply electricity for sale, whether wholesale or retail. ECPF must submit a Title IV permit "Phase II Acid Rain" application to EPD. According to 40 CFR 72.30(b)(2), a complete Acid Rain application must be submitted at least 24 months before the facility commences operation. The Phase II Acid Rain Permit will be issued separately.

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

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[2] A major source under Part 63 is one with potential individual and/or total hazardous air pollutants (HAPS) that equal or exceed 10 tpy and 25 tpy, respectively.

2.4 Title V Operating Permits Program

The Title V program consolidates all air pollution control requirements into a single, comprehensive "Operating Permit" that covers all aspects of new, modified, or reconstructed source's year-to-year air pollution activities. State of Georgia adopted by reference in 391-3-1-.03(10) the Title V regulations. The ECPF must submit a Title V application within 1 year after operation commences.

2.5 Startup, Shutdown and Excess Emissions

Excess emission provisions for startup, shutdown, maintenance, and malfunction are provided in Georgia Rule 391-3-1-.02(2)(a)7. Excess emissions from the turbine stack may result during startup and shutdown.

The PSD short term BACT limits do apply during startup and shutdown, however EPD may allow excess emissions during startup and shutdown provided certain criteria are met. EPD does have enforcement discretion to verify that[3]:

- ✓ To the maximum extent practicable the air pollution control equipment, process equipment, or processes were maintained and operated in a manner consistent with good practice for minimizing emissions;
- ✓ Repairs were made in an expeditious fashion when the operator knew or should have known that applicable emission limitations were being exceeded.
- ✓ The amount and duration of the excess emissions (including any bypass) were minimized to the maximum extent practicable during periods of such emissions;
- ✓ All possible steps were taken to minimize the impact of the excess emissions on ambient air quality; and
- ✓ The excess emissions are not part of a recurring pattern indicative of inadequate design operation, or maintenance.

In addition to the short term BACT limits. EPD has proposed longer term (i.e. lb/day) limits for NOx and CO emissions that specifically include emissions during startup and shutdown. The excess emission provisions for startup and shutdown in Georgia Rule 391-3-1-.02(2)(a)7 do not apply to these lb/day limits.

3.0 CONTROL TECHNOLOGY REVIEW

This section presents the Best Available Control Technology (BACT) analysis for each pollutant emitted at the proposed ECPF, which is subject to the PSD Regulations.

3.1 Definition of BACT

The PSD regulations require that BACT be applied to all regulated pollutants emitted in significant amounts. BACT means an emission limitation where appropriate, based upon the maximum degree of reduction of the pollutant which the permitting authority (EPD), on a case-by-case basis, taking into account energy, environmental, and economic impacts, determines is available and achievable for the source. In all cases BACT must establish emission limitations

[3] EPA Memorandum dated September 28, 1982 entitled, "Policy on Excess Emissions During Startup, Shutdown, Maintenance, and Malfunctions" from Kathleen M. Bennett to Regions I-X.

or specific design characteristics at least as stringent as applicable new source performance standards (NSPS) and must follow a "top-down" approach.

In all cases BACT must establish emission limitations or specific design characteristics at least as stringent as applicable New Source Performance Standards (NSPS). In addition, if EPD determines that there is no economically reasonable or technologically feasible way to measure the emissions, and hence to impose an enforceable emissions standard, it may require the source to use a design, equipment, work practice or operations standard or combination thereof, to reduce emissions of the pollutant to the maximum extent practicable.

The BACT determination should, at a minimum, meet two core requirements.[4] The first core requirement is that the determination follows a "top-down" approach. The second core requirement is that the selection of a particular control system, as BACT must be justified in terms of the statutory criteria and supported by the record, and must explain the basis for the rejection of other more stringent candidate control systems.

EPD's procedures for performing top down BACT analysis are set forth in EPA's Draft New Source Review Workshop Manual (Manual), dated October 1990. One critical step in the BACT analysis is to determine if a control option is technically feasible.[5] If a control is determined to be infeasible, it is eliminated from further consideration. The Manual applies several criteria for determining technical feasibility. The first is straightforward. If the control has been installed and operated by the type of source under review, it is demonstrated and technically feasible.

For controls not demonstrated using this straightforward approach, the Manual applies a more complex approach that involves two concepts for determining technical feasibility: availability and applicability. A technology is considered available if it can be obtained through commercial channels. An available control is applicable if it can be reasonably installed and operated on the source type under consideration. A technology that is available and applicable is technically feasible.

The Manual provides some guidance for determining availability. For example, a control is generally considered available if it has reached the licensing and permitting stages of development. However, the Manual further provides that a source would not be required to experience extended time delays or resource penalties to allow research to be conducted on new technologies. In addition, the applicant is not expected to experience extended trials learning how to apply a technology on a dissimilar source type. Consequently, technologies in the pilot scale testing stages of development are not considered available for BACT.

In addition, as mentioned before, the Manual also requires available technologies to be applicable to the source type under consideration before a control is considered technically feasible. For example, deployment of the control technology on the existing source with similar gas stream characteristics is

[4]The discussion of the core requirements is taken from the Preamble to the Proposed NSR Reform, 61 FR38272.

[5]Discussion on technical feasibility is taken from the PSD Final Determination for AES Londonderry, L.L. C., Rockingham County, New Hampshire. The PSD Final Determination was written by the U.S. EPA Region I, Air Permits Program.

generally sufficient basis for concluding technical feasibility. However, even in this instance, the Manual would allow an applicant to make a demonstration to the contrary. For example, the applicant could show that unresolved technical difficulties with applying a control to the source under consideration (e.g., size of the unit, location of the proposed site and operating problems related to the specific circumstances of the source) make a control technical infeasible.

According to the Environmental Appeals Board (See In re Kawaihae Cogeneration Project, 7 E.A.D. 107 at page 1996, EAB 1997), the section on "collateral environmental impacts" of a proposed technology has been interpreted to mean that "if application of a control system results directly in the release (or removal) of pollutants that are not currently regulated under the Act, the net environmental impact of such emissions is eligible for consideration in making the BACT determination." The Appeals Board continues, "The Administrator has explained that the primary purpose of the collateral impacts clause 'is...to temper the stringency of the technology requirements whenever one or more of the specified collateral impacts–energy, environmental or economic-renders the use of the most effective technology inappropriate."

Lastly, the Appeals Board states, "Unless it is demonstrated to the satisfaction of the permit issuer that such unusual circumstances exist, then the permit applicant must use the most effective technology."

Though a BACT analysis is not required for HAPs, the effectiveness (or impact) of a particular control technology for HAPs must be evaluated. For the ECPF, the primary HAP emitted is formaldehyde. Trace amounts of other HAPs are also emitted as listed on the Combustion Air Toxic Emissions table in Appendix A of the application.

Now that the PSD BACT standards have been defined, the next step is to review the remaining applicable requirements. This step will aid in citing the appropriate legal authority for each requirement in the Title V permit. This analysis will show that the PSD BACT standards represent the most stringent limit.

3.2 Emission Units Applicability

The proposed emission units and the pollutants for which a BACT analysis is required is separated below:

•***Simple-Cycle operation***

Combustion turbine generators (CTGs), diesel-fired water service pump, and fuel preheater - NOx, SO2, CO, TSP/PM10

•***Combined-Cycle operation***

CTGs, diesel-fired water service pump, auxiliary boiler, and fuel preheater - NOx, SO2, CO, and TSP/PM10. Cooling Tower - TSP

3.3 Combustion Turbines

The ECPF is proposing to install two *Simple-Cycle* CTGs that will be converted to *Combined-Cycle* at a later date. The CTGs will operate for 2,672 hours in *Simple-Cycle* combustion mode and 8,760 hours in combined-cycle combustion mode.

3.3.1 Oxides of Nitrogen

Simple Cycle Operation

Xonon

Xonon is an emerging emission control technology that uses catalytic combustion to reduce NO_x emissions from gas turbines to 3.5 ppm. According to the manufacturer, Xonon has successfully reduced NO_x emissions to 3 ppm in laboratory and pilot tests on a small turbine. Xonon uses flameless combustion to burn natural gas and requires no down-stream cleanup device to reduce NO_x emissions. The technique prevents the formation of thermal NO_x during the combustion of fuel and avoids the need for ammonia injection, as with SCR. In the Xonon technology, a fuel and air mixture is oxidized across several small catalyst beds, which combusts the fuel at a temperature lower than that at which thermal NO_x is formed. A partial flame is used downstream to complete the combustion process where unavoidable small amount of NO_x are formed.

Currently, Xonon is not available for large industrial gas turbines such as the GE Frame 7FA. Therefore, it is rejected from further consideration as BACT for this project. EPD is following the development of this technology in order to know when it does become commercially available for this type of project.

High Temperature SCR

One alternative evaluated to reduce NO_X emissions was high temperature *Selective catalytic Reduction* (SCR). SCR is added as a post combustion treatment for NO_X emissions by injecting ammonia (NH_3) into the turbine exhaust stream and upstream from the catalyst unit. The SCR unit houses a catalyst typically made from noble metals, base metal oxides, or zeolite based material. The ammonia injected exhaust stream enters and reacts with the catalyst beds to form N_2 and H_2O. The zeolite-based catalysts typically used for high temperature SCR have even a higher operating temperature range of 800 to 1,100 ^{O}F. The application of a high temperature SCR unit can be reduce NO_x emissions to 5.0 ppmvd at 15 percent oxygen.

Economic Impacts

The calculated average cost effectiveness of high temperature SCR is \$30,842/ton NO_X removed for natural gas combustion. These costs are considered to be cost prohibitive to the operation of the facility. Therefore, high temperature SCR is rejected as a BACT control alternative for the ECPF due to the economic impacts.

Dry Low NO_x Combustion

The application of a Dry Low NO_x (DLN) combustion unit represents the base case for this project. DLN has been demonstrated as BACT for the vast majority of simple cycle combustion turbine projects in the US in the past few years. ECPF proposed a NOx emission concentration of 12.0 ppmvd at 15 percent oxygen. However, EPD believes that a NOx emission rate of 10.0 ppmvd at 15 percent oxygen is achievable based on Method 7E (averaging time of approximately 3-hours on a rolling basis) and therefore we are proposing the BACT limit at this level. This technology has no adverse energy or environmental impacts that would exclude it from being considered as BACT.

Combined Cycle Operation

Xonon

This technology is rejected as BACT for the same reasons described above for Simple Cycle operation.

$SCONO_x$ Technology

A combination of DLN combustion and $SCONO_x$ technology was evaluated for the NO_x control for the combustion turbine generators. $SCONO_x$ system is a pollution control technology that utilizes a catalyst for the reduction of CO and NO_x. The system uses no ammonia, and can operate effectively at temperatures ranging from 300^{O}F to 700^{O}F, making it suited for both new and retrofit applications. The $SCONO_x$ catalyst works by simultaneously oxidizing CO to CO_2, NO to NO_2, and then absorbing NO_2 onto its surface through the use of a potassium carbonate absorber coating.

Economic Impacts

The calculated incremental cost effectiveness from SCR @ 3.5 ppm to SCONOx @ 2 ppm is $92,691/ton NO_x removed. The average cost effectiveness of SCONOx from a baseline of 10 ppm (DLN only) is $17,380/ton NOx removed. The application of SCONOx for the ECPF is rejected as BACT because of adverse economic impacts.

While it is EPD policy to calculate the cost of an emissions control technology based on the total pollutants removed by the technology, if it is capable of removing multiple pollutants, EPD has not done so here because of the extremely high cost associated with this technology for this project. This conclusion is also supported by the fact that SCONOX has never been required as BACT in an attainment area for ozone.

Selective Catalytic Reduction (SCR)

SCR is as a post combustion treatment for NO_X emissions by injecting ammonia (NH3) into the turbine exhaust stream and upstream from the catalyst unit as described above for *Simple Cycle* operation. Ideally the SCR would be located within the HRSG where the temperature is typically stable, thus providing temperatures within the optimum range of the catalyst. ECPF considered a SCR unit capable of achieving a NO_X emission of 3.5 ppmvd at 15% oxygen. This would result in a maximum NO_X emission rate of 24.9 pounds per hour at full load from each CTG.

A review of a RBLC for *Combined Cycle* CTGs firing natural gas indicates BACT emission limits ranging from 3.5 to 10 ppm, based on the application of SCR technology in attainment areas. A listing of permitted facilities from the RBLC is provided in Appendix B of the application.

There are potential environmental impacts associated with the SCR system, although they are not significant. *One possible* adverse environmental impact of this NO_X control system is ammonia slip. A cause of ammonia slip occurs when the exhaust temperature falls outside the optimum catalyst reaction range. A second cause occurs when the catalyst itself becomes prematurely fouled or exceeds its life expectancy. Some ammonia slip will occur regardless of the efficiency of the unit due to the SCR manufacturer's recommendation to inject NH3 above what is stoichiometrically required. This associated ammonia slip will be designed to not exceed 10 ppm to insure that the proposed NO_X emission level is met. Proper control of the ammonia injection will minimize the ammonia slip well below the designed maximum and will maximize NO_X reduction.

The second potential environmental impact is a negligible amount of ammonia salt precipitation, which can be emitted to the atmosphere. The ammonia salt formation is the function of the fuel-bound sulfur content and the amount of excess ammonia in the catalyst bed. The catalyst forms sulfur trioxide, which then mixes with water vapor to form sulfuric acid, which oxidizes the sulfur dioxide in the exhaust stream. This acid then reacts with the free or unreacted ammonia to form ammonia salts that can agglomerate in the exhaust stream as it cools. The potential for formation of ammonia salts is minimal due to the low sulfur content of natural gas.

The third environmental impact is associated with the transportation, handling and storage of aqueous ammonia, which can result in potential spills and evaporation of ammonia into the atmosphere. The overall risk of this occurrence is considered low. There are no anticipated environmental impacts associated with the spent catalyst material, because the metal is shipped back to the manufacturer for recycling.

EPD agrees that BACT for control of NOx emissions during combined cycle operation is a limit of 3.5 ppmvd corrected to 15 percent oxygen based on Method 7E (averaging time of approximately 3-hours on a rolling basis). While there are some negative environmental impacts associated with this technology, they do not warrant that this technology be rejected as BACT.

3.3.2 Carbon Monoxide (CO)

Combustion turbines are designed to combust fuel as completely as possible by incorporating good combustion practices including proper air-to-fuel ratio and a design that adequately accounts for time, temperature, and turbulence conditions within the combustion zone. Three applicable CO control techniques have been identified for combustion turbines. *$SCONO_x$*; *catalytic oxidation*; and *efficient combustion/ design technology* are viable possibilities for CO emissions controls. The application of $SCONO_x$ technology is not feasible for NO_x control, therefore was not considered for CO control.

Catalytic Oxidation Technology

Combined Cycle

Catalytic oxidation of CO is a technically proven control alternative for combustion turbines. The cost-effectiveness is $5,880 per ton CO removed for a 72% reduction of CO emissions (from 9ppm to 2.5ppm). While, this cost may be considered reasonable for the other criteria pollutants (PM10, NOx, SO2, and VOC), it is common to use a lower cost effectiveness threshold as being too expensive for CO control. This is because CO emissions are less of an environmental concern than the other criteria pollutants and is evidenced by the fact that the CO NAAQS is significantly higher than NOx or SO2. Therefore, EPD is rejecting an oxidation catalyst as BACT for CO due to the excessive control costs. A summary of the capital cost, annual cost, cost-effectiveness, environmental and energy impacts of catalytic oxidation to control CO emissions are presented in Table 5-3 of the application.

Simple Cycle

Since the combustion turbines in Simple Cycle mode would only operate 2,672 hours vs. 8,760 hours for the Combined Cycle mode, the cost to control CO emissions in Simple Cycle mode would be significantly greater than the $5,880 per ton cost in Combined Cycle mode. Therefore, EPD is rejecting an oxidation catalyst as BACT for CO due to the excessive control costs.

Good Combustion Practices

The combustion turbines are capable of meeting a CO limit of 9.0 ppmvd at 15% oxygen in both Simple and Combined Cycle mode using good combustion practices. A review of EPA's RBLC database indicates that other combustion turbines have been issued permits with BACT-based CO emissions in the range of 3 to 60 ppm (based on full load operation). There are no expected adverse economic, environmental or energy impacts associated with the proposed control alternative. Thus good combustion practices are proposed as BACT for CO emissions from the combustion turbines.

3.3.3 Sulfur Dioxide (SO_2)

Control techniques available to reduce SO_2 emissions include flue gas desulfurization (FGD) systems and the use of low sulfur fuels. A review of the RLBC indicates that while FGD systems are common on boiler applications, there are no known FGD systems on combustion turbines. Thus, the use of an FGD is rejected as a BACT control alternative. The ECPF will utilize only natural gas in the turbines. The maximum estimated SO_2 emissions factor is proposed to be 0.0034 lb/mmBtu (approximately 2.4 grains/100 scf), which is based on AP-42, Table 3.1-2a (4/00), for both the simple and combined cycle mode of operation. The use of natural gas has an established record as BACT for SO2 emissions. Therefore, the very low SO_2 emission rate that results from the use of natural gas is proposed as BACT for the turbines. There are no expected adverse environmental or energy impacts associated with the proposed control alternative.

3.3.4 Total Suspended Particulates/PM_{10}

Total suspended particulates (TSP) and particulate matter less than 10 micrometers (PM_{10}) will occur from the combustion of natural gas. The EPA's AP-42, Fifth Edition, Supplement B, Section 3, considers particulate matter from natural gas combustion to be less than 1 micron, so all emissions are considered as PM_{10}. The PM_{10} emissions from the combustion of natural gas will result primarily from inert solids contained in the unburned fuel hydrocarbons, which agglomerate to form particles. PM_{10} emission rates from natural gas combustion are inherently low because of very high combustion efficiencies and the clean burning nature of natural gas. Therefore, use of natural gas is in and of itself a highly efficient method of minimizing emissions. The maximum estimated PM_{10} emission rate is 0.015 lb/mmBtu. Based on the EPA's RACT/BACT/LAER Clearinghouse (RBLC) database, there are no BACT precedents that have included an add-on TSP/PM_{10} control requirement for natural gas-fired combustion turbines. Therefore, BACT for PM_{10} emissions from the combustion turbines is proposed to be the use of a low ash fuel and efficient combustion. Typically, plume opacity is not an issue for this type of facility as the exhaust plumes are nearly invisible except for the condensation of moisture during periods of low ambient temperature. The BACT opacity limit is proposed to 10%, which is typical for gas-fired turbines. There are no expected adverse environmental or energy impacts associated with the proposed control alternative.

3.4 Auxiliary Boiler

One natural gas-fired boiler AB1 will be installed during the *Combined Cycle* phase construction and will provide auxiliary steam to the HRSG and steam turbine. The auxiliary boiler has a rated heat input of 17 million BTUs per hour. The auxiliary boiler will fire a maximum of 2,500 hours per year and will vent through a separate stack.

3.4.1 Nitrogen Oxides (NO_X)

The boiler design will incorporate Low NO_X burners for NO_X control, which is common for auxiliary boilers. Due to the intermittent use of this boiler, the use of Low NO_X burners is proposed as BACT for NO_X control of the auxiliary boiler, resulting in a BACT NO_X limit of 0.098 lb/mmBtu. No expected adverse environmental or economic impacts are associated with this NO_X control technology.

3.4.2 Carbon Monoxide (CO)

The control technologies evaluated for use on the natural gas-fired auxiliary boiler include catalytic oxidation and proper boiler design/good operating practices. The cost of add-on controls on intermittently operated facilities is prohibitive. However, controlling boiler-operating conditions can minimize carbon monoxide emissions. This includes proper burner settings, maintenance of burner parts, and sufficient air, residence time, and mixing, for complete combustion. Thus, boiler design and good operating practices are proposed as BACT for controlling the CO emissions from the auxiliary boiler, resulting in a BACT CO limit of 0.082 lb/mmBtu. The proposed BACT will not have any expected adverse environmental or energy impacts.

3.4.3 Sulfur Dioxide (SO_2)

Control techniques available to reduce SO_2 emissions include flue gas desulfurization (FGD) systems and the use of low sulfur fuels. A review of the RLBC indicates that while FGD systems are common on boiler applications, they are not common with boilers firing very low sulfur fuels, such as natural gas. FGD systems are not cost effective because the SO_2 emissions are already minimal. The estimated SO_2 emission rate is 0.06 pounds per hour. Thus, the use of an FGD system is rejected as a BACT control alternative. Therefore, the use of natural gas is proposed as BACT for the auxiliary boiler. There are no expected adverse environmental or energy impacts associated with the proposed control alternative.

3.4.4 Total Suspended Particulates/PM_{10}

Since the auxiliary boiler will fire only natural gas, the maximum estimated TSP/PM_{10} emission rate is 0.007 lb/mmBtu. The EPA's RACT/BACT/LAER Clearinghouse (RBLC) database indicates that there are no BACT precedents for natural gas-fired boilers requiring add-on controls for TSP/PM_{10} emissions. Therefore, BACT for TSP/PM_{10} is proposed to be the use of a low ash fuel and efficient combustion. There are no expected adverse environmental or energy impacts associated with the proposed control alternative.

3.5 Diesel-Fired Water Pump

The diesel-fired water pump DWP1 is a standby emergency unit that will supply water pressure to the fire protection system. The fire protection system provides fire suppression and elimination to the entire facility. The heat input for the diesel powered water pump is estimated to be 2.06 MMBtu per hour. The estimated annual operation will be less than 500 hours and typically operation will consist of only 30 minutes of test firing per week. The BACT determinations for all affected pollutants are as follows:

3.5.1 Nitrogen Oxides (NO_X), Carbon Monoxide (CO), Total Suspended Particulates/PM_{10}

Since the purpose of this unit is only to respond to emergency situations, the BACT limit for NOx, CO, and TSP/PM10 is proposed to a 500 hr/yr limit on a 12-month rolling basis.

3.5.2 Sulfur Dioxide (SO_2)

The only known SO_2 control technique for use on a diesel water pump is the use of low-sulfur diesel fuel. Therefore, the use of low sulfur diesel fuel with a maximum sulfur content of 0.05%, by weight, is the proposed BACT. The proposed BACT will not have any expected adverse environmental or energy impacts.

3.6 Natural Gas-Fired Fuel Preheater

One natural gas-fired fuel preheater FP1 will be installed. The fuel preheater will have a rated heat input of 8.75 MMBtus per hour. The fuel preheater will fire a maximum of 4,000 hours per year during simple-cycle operation and 8,760 hours per year during *Combined-Cycle* operation.

3.6.1 Nitrogen Oxides (NO_X)

A review of the RBLC indicates that fuel preheaters generally have not been required to employ any additional NO_X controls, such as catalytic or non-catalytic reduction type systems, because of the preheater size, low emissions, and operations. Therefore a NO_X emission limit of 0.05 lb/mmBTU is proposed as BACT. The proposed BACT will not have any expected adverse environmental or energy impacts.

3.6.2 Carbon Monoxide (CO)

The control technologies evaluated for use on the natural gas-fired fuel preheaters include catalytic oxidation and proper design/good operating practices. The cost of catalytic oxidation is prohibitive for small units such as the fuel preheaters and thus not considered an economically feasible BACT alternative. Controlling heater-operating conditions can minimize carbon monoxide emissions. This includes proper heat settings, maintenance of preheater parts, and sufficient air, residence time, and mixing for complete combustion. Thus, fuel preheater design and good operating practices are proposed as BACT for controlling the CO emissions from the fuel preheaters, resulting in a BACT CO limit of 0.082 lb/mmBtu. The proposed BACT will not have any expected adverse environmental or energy impacts.

3.6.3 Sulfur Dioxide (SO_2)

Control techniques available to reduce SO_2 emissions include flue gas desulfurization (FGD) systems and the use of low sulfur fuels. A review of the RBLC indicates that these systems are not common with units firing very low sulfur fuels, such as natural gas. FGD systems are not cost effective because the SO_2 emissions are already minimal. The estimated SO_2 emission rate is 0.0034 lbs/MMBtu. Thus, the use of an FGD system is rejected as a BACT control alternative for the fuel preheaters. There are no expected adverse environmental or energy impacts associated with the proposed control alternative.

3.6.4 Total Suspended Particulates/PM_{10}

Since the fuel preheater will fire natural gas, the same properties that applied to the combustion turbines will also apply to this application. The maximum estimated TSP/PM_{10} emission rate is 0.0074 lbs/MMBtu. The EPA's RBLC database indicates that there are no BACT precedents for natural gas-fired preheaters requiring add-on controls, such as bag filtering type units, for TSP/PM_{10} emissions. The use of low ash fuel and efficient combustion are proposed as BACT for controlling TSP/PM_{10} emissions. Opacity is generally not an issue with this type of application, except for the condensation of moisture during periods of low ambient temperature. There are no expected adverse environmental or energy impacts associated with the proposed control alternative.

3.7 Cooling Tower

One cooling tower with 10 cells will be installed during the combined-cycle phase construction. The cooling tower will be multi-celled, mechanical draft, counterflow type with an associated liquid drift. This drift is a source of particulate emission, caused by dissolved and suspended solids inherently contained within the liquid droplets. The water droplets then will evaporate allowing the particulates to agglomerate. The annual operating time is expected to be 8,760 hours. The BACT determination for particulates is as follow:

3.7.1 Total Suspended Particulates/ PM_{10}

There are no technically feasible alternatives that can be installed on the cooling towers, which specifically reduce particulate emissions; however, cooling towers are typically designed with drift elimination features. The drift eliminators are specially designed baffles that collect and remove condensed water droplets in the air stream. These drift eliminators, according to a review of the EPA's RBLC, can reduce drift to 0.0015 percent to 0.004 percent of cooling water flow, which reduces particulate emissions. Therefore the use of drift eliminators is proposed as BACT for cooling tower particulate emissions. The proposed BACT will not have any expected adverse environmental or energy impacts.

4.0 TESTING AND MONITORING REQUIREMENTS

4.1 Combustion Turbine

Under the PSD regulations each CT is subject to BACT requirements for NO_x, CO, SO2, PM/PM_{10} emissions and for visible emissions (opacity). Each CT is also subject to SO2 and NOx emission limitations under the NSPS Subpart GG, however, the BACT limits are much more stringent than the NSPS limits and therefore monitoring that assures compliance with the BACT limits will also assure compliance with the NSPS limits. Under the Acid Rain Regulations each CT is subject to emission requirements for SO_2 emissions and monitoring requirements for SO2 and NOx emissions.

EPD proposes the following initial performance testing requirements:

1. The permit includes a performance test on each CT stack (in both Simple Cycle and Combined Cycle mode) for NO_x emissions to verify compliance with the NO_x BACT emission standard.

2. SO_2 emissions will not be verified through performance testing since the BACT for SO_2 is the use of natural gas only.

3. The permit includes performance tests at base load and at 50 percent load on each CT stack (in both Simple Cycle and Combined Cycle mode) for CO emissions to verify compliance with the CO BACT emission standard.

4. The permit includes performance tests at base load and at 50 percent load on each CT stack (in both Simple Cycle and Combined Cycle mode) for VOC emissions to verify that the facility is not subject to BACT requirements for VOC emissions.

5. No performance test shall be required for PM and visible emissions because of the units burn only natural gas and there is no air pollution control equipment used to reduce these pollutants. The table below summarizes the individual monitoring requirements of the applicable regulations.

EPD proposes the following monitoring requirements:

1. The Acid Rain Regulations (40 CFR Part 75) requires continuous monitoring and recording of NO_x emissions. The NOx CEMS will be used to provide a reasonable assurance of compliance with the NO_x BACT emission limits.

2. The sulfur content of pipeline quality natural gas is very low (typically less than 2 grains/100 scf) and the likelihood of exceeding the NSPS GG fuel sulfur content (0.8 wt.%) is minimal. The alternative custom fuel sulfur-monitoring schedule for NSPS GG is semiannual. Sulfur monitoring shall consist of a semiannual analysis of the pipeline natural gas to verify the assumption that the sulfur content is low (i.e., <0.8 weight percent for NSPS and less than 2.4 grains/100 scf for BACT).

3. A CO CEMS is required in the permit and will be used to assure compliance with the CO BACT limits.

4. No performance test is required to be conducted on two stacks (i.e., combined stacks for turbine and HRSG) while burning natural gas for PM and visible emissions because natural gas is a clean burning fuel. Also, no periodic monitoring for PM and opacity is prescribed.

5. No monitoring of VOC emissions will be required based on the fact that the facility is not subject to BACT requirements for VOC emissions. If the initial performance testing demonstrates that the facility is significant for VOC emissions, then this matter would be revisited.

6. Verification of compliance with the 2,672 hr/yr operational limit for *Simple Cycle* mode will be done by monitoring and recording the CTG's operational time.

4.2 Auxiliary Boiler

Emissions of NO_x and CO will be verified through initial performance testing. No monitoring will be prescribed at this time; however, it will be further researched and addressed during the development of the Title V permit for this facility.

Verification of compliance of the operational limit (i.e., 2,500 hours/yr) will be accomplished by monitoring and recording the boiler's operational time.

4.3 Diesel fired water pump

Sulfur dioxide and particulate matter emissions from the diesel IC engine are minimized through the use of transportation-grade diesel fuel (maximum sulfur content of 0.05 weight percent) and by limiting their 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.

4.4 Natural gas fired preheater

Emissions of NO_x and CO will be verified through initial performance testing. No monitoring will be prescribed at this time; however, it will be further researched and addressed during the development of the Title V permit for this facility.

5.0 AMBIENT AIR QUALITY REVIEW

An air quality analysis is required of the ambient impacts associated with the construction and operation of the proposed modification. The main purpose of the air quality analysis is to demonstrate that emissions emitted from the proposed new major stationary source, in conjunction with other applicable emissions from existing sources (including secondary emissions from growth associated with the new project), will not cause or contribute to a violation of any applicable National Ambient Air Quality Standard (NAAQS) or PSD increment.

In a Class II or Class I area. NAAQS exist for NO_2, CO, PM_{10}, SO_2, Ozone (O_3), and lead (P_b). PSD increments exist for SO_2, NO_2, and PM_{10}.

A separate air quality analysis is required for each of these pollutants to be emitted in a significant amount over the PSD significant threshold. As shown in Table 1, CO, NOx, PM/PM_{10}, and SO2 are to be emitted in amounts over their respective PSD significant thresholds. Thus an air quality analysis must be performed for these air pollutants.

Compliance with any NAAQS is based upon the total estimated air quality, which is the sum of the ambient estimates resulting from existing sources of air pollution (modeled source impacts plus measured background concentrations) and the modeled ambient impact caused by the applicant's proposed emission increase and associated growth. It is important to note that the air quality cannot deteriorate beyond the concentration allowed by the applicable NAAQS, even if not all of the PSD increment is consumed.

The first step in this air quality analysis is to estimate the ambient concentrations that will result from the proposed modification. Dispersion models are the primary tools used to estimate the ambient concentrations that will result from the PSD applicant's proposed emissions in combination with emissions from existing sources. The estimated total concentrations must demonstrate compliance with the applicable NAAQS or PSD increments.

In analyzing the air quality impact from the facility, two levels of modeling were conducted: screening modeling, using an array of hypothetical hourly meteorological conditions with winds blowing in the direction of the highest terrain elevations; and refined modeling, with 5 years of meteorological data and refined terrain elevations. Screening modeling identifies worst case concentrations from the source by assuming winds directed at the highest terrain for any direction at a given distance from the stack. Refined modeling provides a more realistic evaluation of concentrations from the source by examining terrain elevations in all directions and actual recorded hourly meteorology over a 5-year period.

The dispersion models are based upon the assumption that the dispersion of pollutants is primarily a function of: wind speed and direction; atmospheric stability conditions; and the effective point of discharge of the exhaust plume. To predict ambient air concentrations, the models simulate the plume exhausting from the stack, rising a certain distance in the atmosphere, leveling off, and continuing downwind over relatively flat terrain. The concentrations of pollutants are assumed to have a Gaussian distribution about the longitudinal centerline of the plume.

Both simple terrain screening and refined modeling were conducted using the U.S. EPA's Industrial Source Complex Short Term (ISCST3) model. The ISCST3 model combines the evaluated concentrations for a range of possible meteorological conditions for both simple terrain (below stack top) and complex terrain (above stack top).

ISCST3 is a Gaussian plume dispersion model which estimates hour-by-hour ground level concentrations of emissions from an elevated source. The model provides maximum 1-hour, 3-hour, 24-hour, and annual average concentrations for receptors located on a radial grid spaced at ten degree intervals around the source for various downwind distances, and also takes into account the effect of downwash caused by nearby buildings and structures.

The results of modeling analysis for the proposed facility indicate that predicted worst-case concentrations of the pollutants emitted in significant amounts (SO2, PM_{10}, NO_x, and CO) are below PSD significant impact levels. Thus, additional modeling to show compliance with PSD increments and the NAAQS is not required. Modeling input and output files generated in conducting this analysis are available on compact disk. A discussion of this modeling analysis follows.

5.1 Input Data

1. *Meteorological Data* - Surface data from Savannah and upper air data from Waycross for the five-year period from 1982-1986 were used for the Class II area significant impact area modeling analysis. Since relative humidity data were required for the Wolf Island Class I area regional haze analysis using CALPUFF, facility used Savannah/Waycross met data for 1984-1988 for the Class I area significant impact modeling.

2. *Emissions Data* - Emission rates and stack parameters provided by facility on compact disk were used in this evaluation except that for pollutants with both a short-term and long-term standard (SO_2 and PM_{10}), modeling was conservatively conducted using the short-term emission rates only.

3. *Receptor Locations*- The receptor grids provided by facility on compact disk were used in this analysis. For the load analysis, a polar grid with various spacing to 50 km was used. For the refined analysis, a Cartesian grid with a receptor spacing of 100 meters was used to a downwind distance of 3 km. On-site receptors were included in the analysis since the site boundary has not been finalized.

4. *Terrain Elevation*- Even though the site is located in the flat coastal plain, terrain elevations were included in the refined modeling analysis. However, terrain elevations were not included in the load analysis modeling.

5. *Building Downwash*- Building dimensions used by facility for building downwash calculations in the ISCST3 model were verified using the latest version of the BPIP program (Version 95086).

5.2 Load Modeling Analysis

Prior to conducting refined modeling, load modeling was conducted at 50, 75, and 100 percent load conditions and three different ambient operating temperatures for both the simple-cycle and combined-cycle operating modes to determine worst-case operating conditions for each pollutant. Subsequent refined modeling was conducted for all five years of met data for the worst-case scenarios for each pollutant and averaging period (facility only modeled the worst-case year (s) identified in the load modeling analysis for each pollutant). Version 00101 of ISCST3 was used for both load and refined modeling.

5.3 Preconstruction Monitoring Evaluation

Modeling results indicated that none of the pollutants emitted in significant amounts due to the proposed facility would exceed the EPA de minimums concentrations. Thus, the proposed facility is exempted from preconstruction monitoring requirements.

5.4 Significant Impact Area Analysis

The Class II SIA analysis was conducted for NO_x, PM_{10}, SO_2, and CO, the criteria pollutants emitted in significant amounts from the proposed facility. The maximum concentrations for these pollutants for averaging periods of concern were below PSD significant impact levels. Thus, additional modeling to show compliance with PSD Class II increments and the NAAQS is not required.

5.5 Class I Analysis

A Class I analysis including an Air Quality Related Values (AQRV) analysis was requested by the Federal Land Manager for the Wolf Island Class I area which is located about 100 km from the proposed facility. The model used in the regional haze analysis and Class I significant impact analysis was CALPUFF. The maximum PM10, NO2, and SO2 concentrations at the Wolf Island Class I area were well below the proposed Class I area significant impact levels. Thus, additional modeling to show compliance with the PSD Class I increments is not required. Additionally, the modeling results indicate that operation of the proposed facility will not exceed the regional haze threshold values.

5.6 Air Toxic Analysis

Prediction of toxic pollutant concentrations from operation of the proposed facility was based on maximum unit concentrations from the load analysis and maximum emission rates. All of the predicted concentrations were well below Georgia EPD acceptable ambient concentrations (AAC). Air toxic emissions resulting from the operation of the ECPF were modeled using procedures consistent with those contained in the Guideline for Ambient Impact Assessment of Toxic Air Pollutant Emissions Georgia Air Protection Branch, Revised June 21, 1998. The analysis evaluated a list of toxics that have been identified and modeled are listed in Table 6-6 of the application. The emission factors from CTG operation and maximum potential short-term emission rates are also listed in Table 6-7 of the application. Toxic emissions from other supporting equipment (gas preheater and auxiliary boiler) were several orders of magnitude less then the CTG's and were not listed in Table 6-7 of the application. Toxic ambient concentration estimates were based on the maximum unit concentrations from the PSD Class II load analysis. Additional conservatism was added by assuming these rates would occur continuously for a period up to one year.

Acceptable Ambient Concentration (AACs) for twelve toxics was determined by using procedures in the June 1998 guidance document. These procedures are listed in Appendix G of the application, which contains a description of the procedures used.
A spreadsheet was used to calculate final concentration estimates based on the emission rates given in Table 6-6 of the application and the worst-case unit concentration. As required in the modeling guidance the one-hour unit concentrations estimates were adjusted to a 15-minute period by using a factor of 1.32. Table 6-7 presents the final modeling results that demonstrate the ECPF will be in compliance with all applicable AACs.

5.6 Air Quality Analysis Summary

The analysis involved determining maximum impacts on ambient air quality from emissions of NO_x, CO, SO2, and PM10 based on the operation of combustion turbines and auxiliary equipment at the proposed facility. Maximum impacts at receptors located beyond the facility's fence line within Class II and Class I areas were determined using the ISCST3 model. The maximum predicted impacts were compared with applicable PSD significance levels and proposed EPA Class I area significance levels. For all pollutants of concern, the maximum predicted impacts are below the applicable significance levels as well as any applicable ambient standards. A visibility analysis was also conducted and the results demonstrate that plume visual impacts are below the screening criteria. Therefore, the analyses demonstrate that the ECPF will comply with all applicable air quality standards.

6.0 ADDITIONAL IMPACT ANALYSES

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

An additional impact analysis was completed based on existing air quality, the quantity of emissions, and the sensitivity of local soils, vegetation, and visibility in the ECPF's area of potential impact. The additional impact analysis consists of three parts: (1) growth, (2) soils and vegetation impacts, and (3) visibility impairment. Each of these parts is discussed in the sections below.

6.1 Growth Impacts Analysis

The area around the proposed facility includes four counties in Georgia (Chatham, Bryan, Bulloch, and Screven) and two counties in South Carolina (Jasper and Hampton). The Savannah River forms the eastern border separating it from South Carolina.

The peak on-site construction force is expected to be approximately 100 people. Operation of the proposed combustion turbine facility will not significantly alter the economic conditions of the Effingham County area. Personnel staffing levels will be approximately ten people to operate the facility and additional support services will provide opportunities for local facilities. Residential, industrial, and commercial growth in the area accompanying the proposed facility is expected to be minimal. Therefore, air emissions associated with this growth are negligible.

6.2 Effects of Soil

Because the predicted concentrations of all pollutants from the proposed combustion turbine facility are well below the significant impact levels, local atmospheric deposition of emissions from the facility will be very low. Therefore, adverse impacts on local soils are not expected.

6.4 Effects on Vegetation

The modeling results demonstrate that the emissions from the proposed combustion turbine facility are not in excess of the NAAQS or other thresholds of concern given in the PSD regulations. The major criteria pollutants evaluated included SO_2, NO_x, CO, and particulates. The predicted ambient air impacts associated with the operation of the facility are considered insignificant and therefore are not expected to cause any significant adverse effects on vegetation including crops and timber land around the facility.

6.5 Visibility Impairment Analysis

Visibility is affected primarily by PM and NO_X emissions. A visibility analysis was performed using the plume visual impact-screening model VISCREEN (version 88341). The results of the level 1 screening analysis are discussed in Section 6. There are two PSD Class I areas located within 200 kilometers of the proposed site. These Class I areas are the Wolf Island Wildlife Refuge and the Cape Romain Wildlife Refuge. The nearest PSD Class I area is the Wolf Island Wildlife Refuge located approximately 100.6 kilometers south of the proposed plant site. The Cape Romain Wildlife Refuge is located approximately 167 kilometers northeast of the proposed plant site. Based on the conservative results of the level 1 screening analysis, ECPF has demonstrated that the Project will not have an adverse impact on the visibility of any Class I area and more refined analyses are not required.