JEA - Greenland Energy Center
Simple Cycle Combustion Turbines 1 and 2

PSD Construction Permit Application

April 2008

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JEA – Greenland Energy Center
Units 1 and 2
Simple Cycle Combustion Turbines

Prevention of Significant Deterioration
Air Permit Application

April 2008

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Acronym List

AERMIC	AMS/EPA Regulatory Model Improvement Committee
AMS/EPA	American Meteorological Society/Environmental Protection Agency
AQIA	Air Quality Impact Analysis
AQRV	Air Quality Related Value
BACT	Best Available Control Technology
bhp	Brake Horsepower
BPIPPRM	Building Profile Input Program Prime
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CALPUFF	California Puff
CAMR	Clean Air Mercury Rule
CCCT	Combined Cycle Combustion Turbine
CEMS	Continuous Emissions Monitoring System
CFR	Code of Federal Regulations
CIPP	Cane Island Power Park
CO	Carbon Monoxide
CTG	Combustion Turbine Generator
CWA	Chassahowitzka Wilderness Area
DAT	Deposition Analysis Threshold
DEM	Digital Elevation Model
DLN	Dry Low NO_x Burner
dv	Deciview
EC	Elemental Carbon
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
FDEP	Florida Department of Environmental Protection
FWS	Fish and Wildlife Service
GE	General Electric
GEP	Good Engineering Practice
H_2S	Hydrogen Sulfide
H_2SO_4	Sulfuric Acid Mist
ha	Hectares
HAP	Hazardous Air Pollutant
Hg	Mercury
hr	Hour

HRSG	Heat Recovery Steam Generator
ISO	International Organization for Standardization
IWAQM	Interagency Workgroup on Air Quality Modeling
kgal/yr	Kilo gallons (or 1,000 gallons) per year
kW	Kilowatt
lb/h	Pound per Hour
LCC	Lambert Conformal Conic
MBtu	Million British Thermal Unit
MSA	Metropolitan Statistical Area
MW	Megawatt
NAAQS	National Ambient Air Quality Standards
NESHAP	National Emission Standards for Hazardous Air Pollutants
ng/J	Nanogram per Joule
NO_x	Nitrogen Oxides
NSPS	New Source Performance Standard
NSR	New Source Review
O3	Ozone
Pb	Lead
PM/PM10	Particulate Matter/Particulate Matter Less than 10 Microns
ppm	Parts per Million
ppmvd	Parts per Million Volumetric Dry
PRIME	Plume Rise Model Enhancement
PSD	Prevention of Significant Deterioration
psig	Pounds Per Square Inch Gauge
PTE	Potential To Emit
RICE	Reciprocating Internal Combustion Engines
RH	Relative Humidity
rpm	Revolutions Per Minute
scf	Standard Cubic Feet
SCCT	Simple Cycle Combustion Turbine
SCR	Selective Catalytic Reduction
GEC	Greenland Energy Center
SER	Significant Emission Rates
SIL	Significant Impact Level
SO_2	Sulfur Dioxide
SOA	Secondary Organic Aerosols
STG	Steam Turbine Generator

tpy	Tons per Year
ULSFO	Ultra-Low Sulfur Fuel Oil
USEPA	United States Environmental Protection Agency
USGS	United States Geological Survey
VOC	Volatile Organic Compound
vr	Visual Range
WGS	World Geodetic System
yr	Year

1.0 Introduction

JEA proposes to construct a new electric-generating facility (hereinafter referred to as Greenland Energy Center, GEC or the Project) in Jacksonville in Duval County, Florida. The power block at the GEC will consist of two General Electric (GE) 7FA-combustion turbine generators (CTGs) operating in simple cycle mode with an exhaust stack for each CTG. The CTGs will have the capability to fire natural gas (note: the pipeline may transport vaporized liquefied natural gas, which is the same as natural gas), and ultra low sulfur fuel oil (ULSFO). Each CTG has a nominal rating of 176 MW while firing natural gas and 190 MW while firing ULSFO, at an ambient temperature of 59°F and a relative humidity of 60 percent (hereinafter referred to as International Organization for Standardization (ISO) conditions). This configuration will produce a nominal plant output of 352 MW on natural gas and 380 MW on ULSFO at ISO conditions. The GEC will function as a peaking power plant.

In addition to the CTGs, JEA also proposes to install an emergency diesel fire pump, an emergency diesel engine generator, two 1.875 million gallon ULSFO storage tanks and a fuel gas heater as part of the proposed facility. The details of these systems are provided in Section 2.2.

2.0 Project Characterization

The following sections briefly characterize the Project, including a general description of the location, facility, and potential emission units, as well as a summary of the estimated emissions and a discussion of New Source Review (NSR) applicability.

2.1 Project Location

The GEC will be located in Duval County, in the City of Jacksonville. Duval County is classified as an attainment area for all criteria air pollutants. The average site elevation is 30 feet and the terrain surrounding the site is flat. The approximate UTM coordinates of the site are 450,266 m East and 3,336,445 m North (Zone 17, NAD 27). The site location is shown in Figure 2-1.

2.2 Description of Equipment and Emission Units

The major combustion equipment at the GEC will consist of two CTGs, each having the capability to fire both natural gas and ULSFO. Emissions control equipment will consist of dry low NO_x (DLN) combustors while firing natural gas, and a combination of DLN combustors with water injection in the CTGs for NO_x control during ULSFO combustion. The Project consists of the following major pieces of equipment:

- Two GE 7FA CTGs capable of firing natural gas or ULSFO.
- One 350 brake horsepower (bhp) emergency diesel fire pump used as a backup for emergency water supply, including a 500 gallon ULSFO day tank.
- One 1,500 kW emergency diesel engine generator with a 2,500 gallon ULSFO day tank.
- One 5.84 MBtu/h natural gas fired fuel gas heater.
- Two 1.875 million-gallon ULSFO storage tanks.

The site arrangement of the Project is presented on Appendix A. Table 2-1 summarizes the emission units and corresponding operating limits in this application.

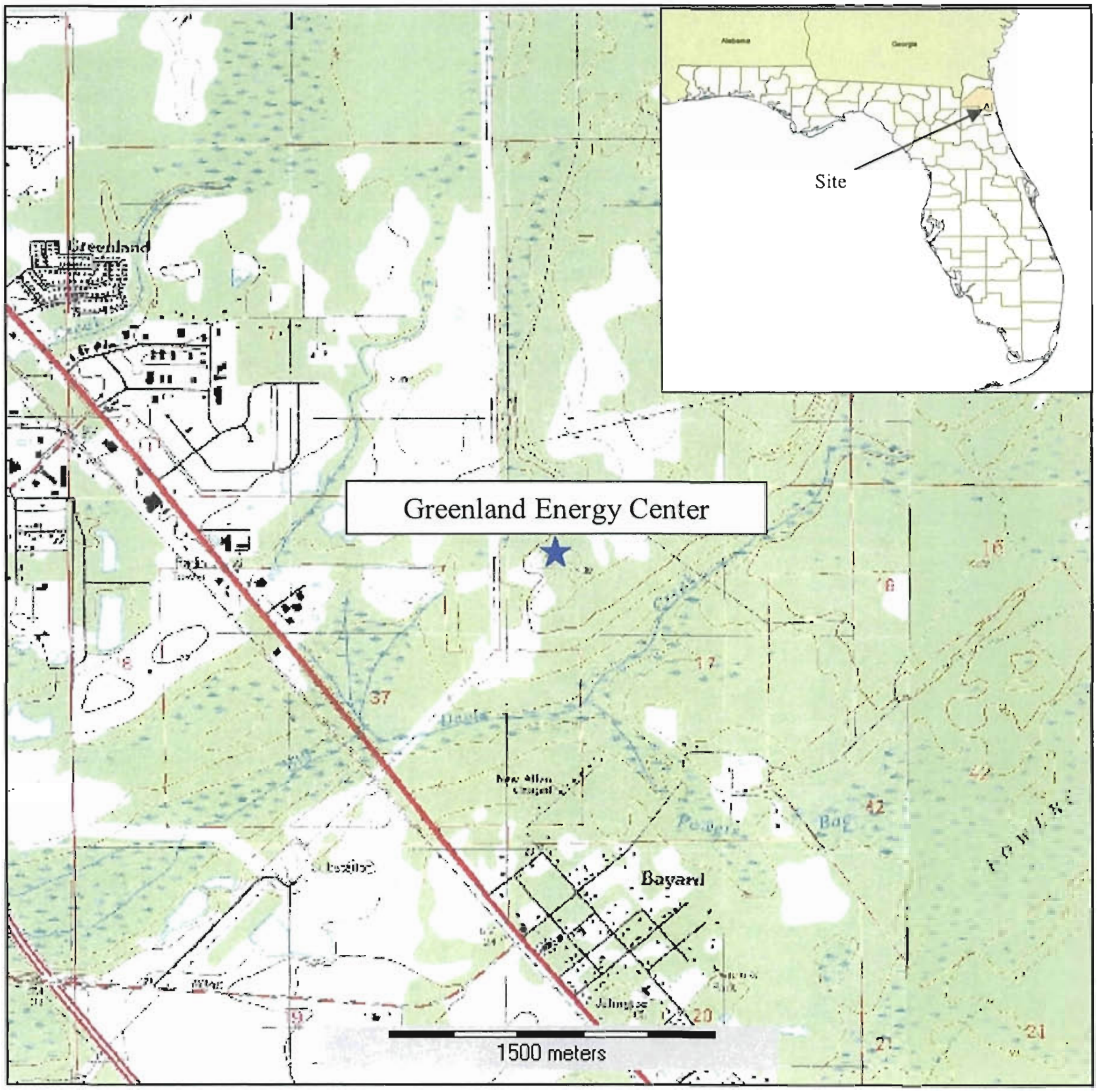

Figure 2-1
Area Map and Proposed Project Location

2.2.1 Combustion Turbines

This application is based on installation of two GE 7FA CTGs operating in simple cycle mode. Each CTG will include the following major features:

- Dual fuel firing system using natural gas or ULSFO.
- Dry low NO_x combustion system for NO_x reduction when firing natural gas, and water injection while firing ULSFO.
- Static inlet air filtration.
- Mark VI control system.

The fuel for GEC will be natural gas and ULSFO (0.0015 percent sulfur or 15 ppm sulfur). Natural gas will be delivered to the site by a new pipeline. ULSFO delivery will be by truck. A truck unloading and transfer station along with two 1.875 million gallon ULSFO storage tanks will be constructed.

2.2.2 Emergency Diesel Fire Pump

The 350 bhp emergency diesel fire pump along with the emergency diesel engine will not use more than 32,000 gallons per year of diesel. The fire pump will fire ULSFO. Annual emissions from the emergency diesel fire pump are based on 7,000 gallons per year of diesel fuel and 100 percent load, which corresponds to approximately 400 hours per year of operation. These annual emissions are included in the facility potential emissions used for determining permit applicability.

2.2.3 Emergency Diesel Engine Generator

The 1,500 kilowatt (kW) emergency diesel engine generator along with the emergency diesel fire pump will not use more than 32,000 gallons per year of diesel. The emergency diesel engine generator will provide backup power in the event the normal sources of auxiliary power are lost and it is JEA's desire to maintain operability of critical systems such as battery chargers and air conditioning of critical components. If the auxiliary power is lost while in operation the emergency diesel engine generator will assist in the orderly cooldown of equipment, and basic functions in the plant including "house loads" will be maintained. The emergency diesel engine generator will fire ULSFO. Annual emissions from the emergency diesel engine generator are based on 25,000 gallons per year of diesel fuel and 100 percent load, which corresponds to approximately 230 hours per year of operation. These annual emissions are included in the facility potential emissions calculations.

2.2.4 Fuel Gas Heater

The fuel gas heater will be used to heat natural gas to the dew point temperature. A 5.84 MBtu/h natural gas fired fuel gas heater will be installed.

2.2.5 ULSFO Storage Tanks

Two 1.875 million gallon ULSFO storage tanks will be installed for operation of the CTGs on ULSFO. It is expected that some volatile organic compounds (VOCs) will be emitted in the form of standing and working losses from the storage tanks. The VOC emissions are included in the facility potential annual emissions calculations.

2.2.6 Mode of Operation

Table 2-1 summarizes the emission units and corresponding operating limits proposed in this application.

Two operating scenarios are proposed in this application that correspond to the availability of natural gas fuel onsite. Under the first operating scenario (Scenario 1 - Pre-Onsite Natural Gas Availability), it is assumed that natural gas is not available onsite, and the Project will burn ULSFO exclusively. The second operating scenario (Scenario 2 - Post-Onsite Natural Gas Availability) is based on the availability of natural gas onsite, and the combustion of ULSFO as a back-up fuel. When natural gas becomes available on site, Scenario 1 will discontinue, and the Project will continue to operate under the conditions of Scenario 2. The following describes the proposed fuel and operating limits associated the aforementioned scenarios:

- **Scenario 1 (Pre-Onsite Natural Gas Availability):** Prior to the completion of the natural gas pipeline to the site, the Project will have no access to natural gas for combustion as the primary fuel, and will be limited to the use of USLFO. Under this scenario, JEA proposes to fire ULSFO for not more than 1,000 hours per year per CTG. JEA requests that the Project be limited to a combined ULSFO usage of 30,213 thousand gallons per year (kgal/yr, equivalent to 1,000 hours of full load ULSFO firing per year per CTG) instead of an hourly operational limit. Scenario 1 applies until such time as the natural gas pipeline construction is complete and commercial operation on natural gas is successfully achieved for the CTGs.
- **Scenario 2 (Post-Onsite Natural Gas Availability):** When the natural gas pipeline construction is complete and natural gas fuel is available onsite and commercial operation on natural gas has been successfully achieved on each CTG, JEA proposes to fire each simple cycle CTG for 3,500 hours per year, with up to 500 hours of that total on ULSFO and the balance on natural gas.

Both operating scenarios described above are fully addressed in this application, including the air quality impact analyses and BACT determination. Additionally, as further explained in Section 5.0 of this document, each CTG will also be restricted to 17 hours of operation of maximum ULSFO use per calendar day for compliance with regional haze impact thresholds. This translates to a requested daily ULSFO usage limit of 277 kgal/day per CTG.

Table 2-1
Summary of Sources to be Permitted

Emission Units	Heat Input per Unit (MBtu/h)	Operational Limits
Each of the two CTGs[a]	1,977 (natural gas, 7 °F) 1,806 (natural gas, ISO)	Pre-Onsite Natural Gas Availability: 30,213 kgal/yr for two CTGS combined
	2,153 (ULSFO, 7 °F) 1,994 (ULSFO, ISO)	Post-Onsite Natural Gas Availability: 3,500 hours per CTG per year, with up to 500 hours of that total per CTG on ULSFO and the balance on natural gas
Emergency Diesel Fire Pump[b]	2.38	Emergency diesel engine generator and emergency diesel fire pump will collectively burn less than 32,000 gallons per year of diesel.
Emergency Diesel Engine Generator[b]	14.70	
Fuel Gas Heater	5.84	None
Two 1.875 Million Gallon ULSFO Storage Tanks	N/A	N/A

[a]Heat input for each CTG based on higher heating value (HHV) at 100 percent load. Data based on GE performance guarantee.
[b]Heat input for emergency diesel fire pump and emergency diesel engine generator based on fuel consumption rate of 17 gallons per hour (gph) and 105 gph, respectively, and a diesel calorific value of 140,000 Btu/gallon.

2.3 Project Emissions

This section discusses the potential to emit (PTE) of regulated and criteria air pollutants resulting from the GEC. Emissions from the GEC will be generated from the two General Electric 7FA CTGs and other ancillary equipment identified above.

Performance data for each CTG at 100 percent load with natural gas or ULSFO firing at ISO conditions were used to determine the PTE.

Ambient temperature data were selected based on meteorological data from Duval County, Florida. An ambient temperature of 7° F represents the seasonal minimum site temperature and corresponds to maximum heat input and power generation. An ambient temperature of 68.8° F represents the average annual site temperature, which is representative of the average heat input rate. An ambient temperature of 105° F represents the seasonal maximum site temperature and corresponds to the lowest heat input rate for the combustion turbine. A temperature of 59° F represents ISO conditions.

2.3.1 Units 1 and 2 CTGs

The maximum and potential (at ISO conditions) pound per hour emission rates are presented in Table 2-2. Appendix B provides the performance data for each CTG.

Table 2-2
CTG Emission Rates (lb/h)

Pollutant	Natural Gas Firing (lb/h)		ULSFO Firing (lb/h)	
	Maximum[a]	At 59°F (ISO)[b]	Maximum[a]	At 59°F (ISO)[b]
NO_x[c]	64.00	58.50	355.70	329.40
SO_2[d]	9.01	8.23	2.65	2.45
CO[e]	25.30	16.20	55.10	38.20
PM/PM_{10} (front and back half)	18.00	18.00	34.00	34.00
VOC	3.10	2.90	6.20	4.30
Sulfuric Acid Mist (SAM)	3.45	3.15	1.01	0.94

[a]Maximum pound per hour emission rates for each CTG considering all operating loads and ambient temperatures.
[b] Emission rates at ISO Conditions are for the 100 percent load case only.
[c]NO_x emissions at ISO conditions are based on a NO_x emission rate of 9.0 ppmvd at 15 percent O_2 when firing natural gas and 42.0 ppmvd at 15 percent O_2 when firing ULSFO.
[d]Based on a natural gas sulfur content of 2 grains/100 scf and the use of ULSFO with 0.0015 percent sulfur content.
[e]CO emissions at ISO conditions are based on a CO emission rate of 4.1 ppmvd at 15 percent O_2 when firing natural gas and 8.0 ppmvd @ 15 percent O_2 when firing ULSFO.

2.3.2 Emergency Diesel Fire Pump

A 350 bhp emergency diesel fire pump is proposed to be installed. The manufacturer specification sheet is provided in Appendix B. The emissions calculations for the emergency diesel fire pump were derived from a combination of vendor data and in-house estimates with the unit firing ULSFO and are presented in Appendix C. Annual emissions from the emergency diesel fire pump were based on 400 hours per year of operation.

2.3.3 Emergency Diesel Engine Generator

The 1,500 kW emergency diesel engine generator will fire only ULSFO. Under normal operating situations, the emergency diesel engine generator will only be run for short test periods when the plant is running. It is estimated that the emergency generator will operate approximately 230 hours per year. Potential emissions are based on vendor data, presented in Appendix B. Detailed emissions calculations are presented in Appendix C.

2.3.4 Fuel Gas Heater

The fuel gas heater will be used to heat natural gas to the dew point temperature and will operate only when the CTGs are firing natural gas. The 5.84 MBtu/h fuel gas heater could conservatively operate up to 8,760 hours per year. Potential emissions are based on vendor data, presented in Appendix B. Detailed emissions calculations are presented in Appendix C.

2.3.5 ULSFO Storage Tanks

The VOC emissions from the two 1.875 million gallon ULSFO storage tanks were estimated using the USEPA TANKS 4.0.9d. Emissions from the two day tanks that store ULSFO for the emergency equipment will be insignificant. Detailed emissions calculations are presented in Appendix C.

2.4 GEC Potential to Emit

The annual PTE for GEC was estimated based on the hourly emission rate for each pollutant at ISO conditions, considering operation at 100 percent load, as well as the emissions from the other ancillary emission units. The annual PTE was then calculated for each of the two operational modes presented in Sections 2.2.6. Table 2-3 summarizes the facility PTE. The GEC PTE presented in Table 2-3 is based on the higher of firing either:

- 1,000 hours of ULSFO per CTG per year (pre-onsite natural gas availability); <u>or</u>

- 3,500 hours per year per CTG on natural gas (post-onsite natural gas availability); or
- 3,000 hours per year per CTG on natural gas with 500 hours per year per CTG on ULSFO (post-onsite natural gas availability).

Appendix C provides the detailed emission calculations.

2.4.1 Hazardous Air Pollutant Emissions

The GEC will not be a major source of hazardous air pollutants. Refer to Appendix C for hazardous air pollutant emission calculations.

Table 2-3
GEC Potential to Emit (tpy)

Pollutant	Two CTGs[(a)]	Emergency Diesel Fire Pump[(b)]	Emergency Diesel Engine Generator[(b)]	Fuel Gas Heater[(c)]	Storage Tanks	Total
NO_x	340.20	0.57	3.33	2.41	NA	346.51
SO_2	28.81	0.00	0.00	0.02	NA	28.82
CO	67.70	0.07	0.45	2.02	NA	70.24
PM/PM_{10}	71.00	0.03	0.02	0.19	NA	71.25
VOC	10.85	0.08	0.08	1.27	0.71	13.00
SAM	11.03	0.00	0.00	0.02	NA	11.05

[(a)]PTE from CTGs based on ISO conditions and operation at 100 percent load. Highest PTE occurs in the post-onsite natural gas availability scenario. The PTE is the expected emissions from combustion turbine operation at 3,500 hours per CTG per year on natural gas alone or the combination of natural gas/ULSFO (3,000 hours per CTG per year on natural gas and 500 hours per CTG per year on ULSFO); whichever is greater.
[(b)]PTE from emergency equipment based on a combined fuel usage of not more than 32,000 gallons per year.
[(c)]PTE from the fuel gas heater is conservatively based on the unit firing natural gas for 8,760 hours per year.

2.5 Federal and State Air Quality Requirements

This section provides a review of rule applicability for the facility and the various emission units that are part of the Project.

2.5.1 Rule Applicability to the Facility

This section provides a review of the New Source Review (NSR) applicability for the facility.

2.5.1.1 New Source Review. The federal Clean Air Act (CAA) NSR provisions are implemented for new major stationary sources and major modifications at existing major sources under two programs; the PSD program outlined in 40 CFR 52.21 for areas in attainment, and the NSR program outlined in 40 CFR 51 and 52 for areas considered nonattainment for certain pollutants.

The air quality in a given area is generally designated as being in attainment for a pollutant if the monitored concentrations of that pollutant are less than the applicable Ambient Air Quality Standards (AAQS). Likewise, a given area is generally classified as nonattainment for a pollutant if the monitored concentrations of that pollutant in the area are above the AAQS. A review of the air quality attainment status of Duval County reveals that the proposed Project is located in an attainment or unclassifiable area with respect to all pollutants. As such, the PSD program will apply to the proposed Project, as administered by the state of Florida under 62-212.400, F.A.C., *Stationary Sources – Preconstruction Review, Prevention of Significant Deterioration.*

2.5.1.2 Prevention of Significant Deterioration. The PSD regulations are designed to ensure that the air quality in existing attainment areas does not significantly deteriorate or exceed the AAQS while providing a margin for future industrial and commercial growth. The primary provisions of the PSD regulations require that major modifications and new major stationary sources be reviewed prior to construction to ensure compliance with the AAQS, the applicable PSD air quality increments, and the requirements to apply BACT.

A major stationary source is defined as any one of the listed major source categories that emits, or has the PTE, 100 tons per year (tpy) or more of any regulated pollutant, or 250 tpy or more of any regulated pollutant if the stationary source does not fall under one of the listed major source categories. As discussed during the project introduction meeting with the Florida Department of Environmental Protection (FDEP) on February 6, 2008, JEA ultimately plans to convert the simple cycle units to combined cycle combustion turbines (CCCT). FDEP therefore informed JEA that NSR/PSD permit applicability for the simple cycle project is to be based on the PTE of the combined cycle conversion project.

Future Combined Cycle Operations. The power block of the possible future combined cycle operations is expected to consist of a 2 x 1 combined cycle configuration which includes two CTGs (the currently proposed simple cycle units), two heat recovery steam generators (HRSGs), and one steam turbine generator (STG). This configuration would produce a nominal plant output of approximately 570 MW. The HRSGs would also be equipped with duct burners that generate additional heat input to increase the steam generating capacity of the HRSGs. Each CTG/HRSG would have a single exhaust stack and a simple cycle by-pass stack. Since conceptual engineering on the combined cycle generation has not been completed, potential emissions from the combined cycle facility are preliminary in nature for the purposes of this application. It is expected that the combined cycle units would operate primarily on natural gas, with up to 500 hours per year per unit on ULSFO as a back-up.

The future combined cycle facility would qualify as one of the 28 major source named categories (i.e., fossil fuel fired steam electric plant) and will have a PTE greater than 100 tpy for at least one regulated pollutant. The preliminary maximum and potential (at ISO conditions) pound per hour emission rates for the combined cycle units are presented in Table 2-4. Table 2-5 presents the estimated PTE from the combined cycle units, and as shown, the estimated PTE of NO_x, CO, PM/PM_{10}, and H_2SO_4 exceed the PSD significant emission rates of 40, 100, 25/15, and 7 tpy, respectively. Therefore, the preceding pollutants would be subject to PSD review for the combined cycle operations. Since these pollutants would be subject to PSD review for the combined cycle operations, per FDEP guidance, the same pollutants will also be subject to PSD for the simple cycle project. The PSD review includes a BACT analysis, an AQIA, and an assessment of the GEC's total impact on general residential and commercial growth, soils and vegetation, and visibility, as well as a Class I area impact analysis. These analyses, while triggered by the PTE of the future combined cycle operations, are performed for the simple cycle project and are included in Sections 3.0, 4.0, and 5.0, respectively.

JEA also performed an AAQIA for the possible future combined cycle facility. This AAQIA (see Appendix F) considered the two combustion turbines operating in combined cycle mode. Emissions and performance data for the combined cycle AAQIA are preliminary and intended to demonstrate GEC's ability to comply with the modeling thresholds post-combined cycle conversion. A NSR/PSD application for the combined cycle conversion will include a more comprehensive AAQIA for the project.

2.5.2 Rule Applicability to Units 1 and 2 Simple Cycle CTGs

The following sections include a discussion of the applicability of regulations to the Units 1 and 2 combustion turbines.

2.5.2.1 New Source Performance Standards. The New Source Performance Standards (NSPS) established in the 1970 CAA, were developed for specific industrial categories and are promulgated in 40 CFR 60 and adopted by reference in Rule 62-204.800(8)(b)39, F.A.C.

Table 2-4
2 x 1 CCCT Preliminary Emission Rates (lb/h)

Pollutant	Natural Gas Firing (lb/h)		ULSFO Firing (lb/h)	
	Maximum[a]	At 59°F (ISO)[b]	Maximum[a]	At 59°F (ISO)[b]
NO_x[c]	14.0	13.1	73.4	69.0
SO_2[d]	8.8	8.3	3.4	3.2
CO	30.6	28.2	41.4	38.8
PM/PM_{10} (front and back half)	24.0	23.7	39.6	39.3
VOC	4.0	3.9	5.6	5.2
Sulfuric Acid Mist (SAM)	5.3	5.0	1.7	1.6

(a)Maximum pound per hour emission rates for each CCCT considering all operating loads and ambient temperatures.
(b)Emission rates at ISO Conditions are for the 100 percent load case only.
(c)NO_x emissions at ISO conditions are based on a NO_x emission rate of 2.0 ppmvd at 15 percent O_2 when firing natural gas and 8 ppmvd at 15 percent O_2 when firing ULSFO.
(d)Based on a natural gas sulfur content of 2 grains/100 scf and the use of ULSFO with 0.0015 percent sulfur content.

Table 2-5
GEC Combined and Simple Cycle PTE and PSD Applicability (tpy)

Pollutant	Combined Cycle PTE[a]	Simple Cycle PTE[b]	PSD Significant Emission Rate	Simple Cycle Subject to PSD[c]
NO_x	142.58	346.51	40	Yes
SO_2	72.65	28.82	40	**Yes**
CO	251.89	70.24	100	**Yes**
PM/PM_{10}	215.41	71.25	25/15	Yes
VOC	34.40	13.00	40	No
SAM	43.49	11.05	7	Yes

Notes: Bolded text indicates those pollutants that will be subject to PSD as the result of emissions from the possible future combined cycle conversion.

[a]PTE based on the higher of firing either 8,760 hours per year on natural gas or 8,260 hours per year on natural gas with 500 hours per year on ULSFO, at ISO conditions. Refer to Appendix C for emission calculations from the combined cycle turbines. NO_x emissions in combined cycle mode controlled by a selective catalytic reduction (SCR) system, and good combustion controls for other pollutants (however, a detailed BACT analysis will be performed in the future application for combined cycle operation).
[b]From Table 2-3.
[c]PSD review for the simple cycle project is based on the expected PTE of the future combined cycle operation.

Both of the combustion turbines are subject to *Standards of Performance for Stationary Combustion Turbines*. The NSPS are found at 40 CFR Part 60 Subpart KKKK and are adopted by reference in Rule 62-204.800(8)(b)77, F.A.C. Subpart KKKK includes standards for regulation of NO_x and SO_2 as follows:

- NO_x--15 ppm (parts per million) at 15 percent O_2 or 54 ng/J (nanogram per joule) of useful output (0.43 lb/MWh) – new turbines firing natural gas with > 850 MBtu/h heat input.
- NO_x--42 ppm (parts per million) at 15 percent O_2 or 160 ng/J (nanogram per joule) of useful output (1.3 lb/MWh) – new turbines firing fuel oil with > 850 MBtu/h heat input.
- NO_x--96 ppm at 15 percent O_2 or 590 ng/J of useful output (4.7 lb/MWh) – turbines operating at less than 75 percent of peak load – turbines with > 30 MW output.
- SO_2--The rule includes a fuel emission standard or a fuel sulfur standard equivalent to potential SO_2 emissions of 0.060 lb SO_2/MBtu.

The criteria for this NSPS will be met or exceeded by the proposed project.

2.5.2.2 National Emission Standards for Hazardous Air Pollutants. On March 5, 2004, the United States Environmental Protection Agency (USEPA) published final National Emission Standards for Hazardous Air Pollutants (NESHAP) for stationary combustion turbines. This rule, found at 40 CFR Part 63 Subpart YYYY, is commonly referred to as the CT MACT. The CT MACT is applicable to stationary gas turbines located at major sources of hazardous air pollutants (HAPs). A major source of HAPs is a site that emits or has the potential to emit any single HAP at a rate of 10 tons or more per year or any combination of HAP at a rate of 25 tons or more per year.

Potential annual HAP emissions from the GEC are based on the AP-42 HAP emission factors. It should be noted that the formaldehyde emission factor for the CTGs firing natural gas was obtained from the USEPA AP-42 Access Database (Combustion Turbine Emissions Database v.5; http://www.epa.gov/ttn/atw/combust/turbine/turbpg.html). The emission factor is an average of the emission factors listed for GE Frame 7F machines at 100 percent load and lean pre-mix technology. The Access Database emission factor for formaldehyde is more representative than the emission factor listed in AP-42 Table 3.1-3, which is based on an average emission factor across various types of CTGs.

As shown in the HAP emission tables in Appendix C, no individual HAP has a PTE in excess of 10 tpy and no combination of HAPs has a PTE in excess of 25 tpy from the GEC. The potential to emit of all HAPs combined is 4.88 tpy for the GEC across all operating scenarios. Because, the potential emissions of all HAPs, both individually and combined, are less than the HAP major source threshold levels of 10 tpy for individual HAPs and 25 tpy for combined HAPs (10/25 tpy), the GEC is a minor source for HAP emissions and therefore not subject to the CT MACT. The future combined cycle conversion is also expected to be a minor source of HAPs.

2.5.3 Rule Applicability to the Emergency Diesel Fire Pump and the Emergency Diesel Engine Generator

Reciprocating internal combustion engines (RICE) rated greater than 500 bhp and located at major HAP sources are regulated by the RICE MACT (40 CFR Part 63, Subpart ZZZZ). The GEC is not a major source of HAPs and consequently the diesel fire pump and the emergency diesel engine generator are exempt from the requirements of the RICE MACT.

The emergency diesel fire pump and emergency diesel engine generator will also be subject to the manufacturer's certification requirements of compliance under the NSPS for RICE (40 CFR Part 60, Subpart IIII). The rule provides various emission standards based on the engine's classification, use, manufacture date, and engine size. The applicable standards associated with the emergency diesel engine generator will be dependent on the engine model year. Therefore, the exact emission standards applicable to the emergency diesel engine generator cannot be identified until the engine is purchased. The emergency diesel fire pump will need to meet the emission requirements listed in Table 4 of the NSPS regulation.

Regardless of the applicable emissions requirements imposed by this NSPS, beginning with engines manufactured in model year 2007 (for emergency engines) and 2008 (for fire pump engines), the onus of this rule falls on the manufacturer of these engines as they are required to manufacture engines that comply with the rule. The only requirement of this rule for owners and operators of these units is that they purchase certified engines. JEA will purchase certified engines that will meet the appropriate emission limits.

2.5.4 Excess Emissions

As with other combustion turbines of this size and type, excess emissions during startup, shutdown, malfunction, DLN tuning, and fuel switching are likely to occur and are accounted for in FDEP permitting of combustion turbines. In accordance with Rule 62-210.700, F.A.C., JEA is requesting that the permit allow for 2 hours of excess emissions in any 24 hour period due to startup, shutdown, malfunction or fuel switching (a fuel switch is considered a form of startup). It is also recognized that excess emissions may occur during DLN tuning. JEA is requesting that the permit include the following condition in regards to allowing for excess emissions during DLN tuning sessions.

> *"DLN tuning: CEMS data collected during initial or other DLN tuning sessions may be excluded from the compliance demonstrations provided the tuning session is performed in accordance with the manufacturer's specifications or determined best practices. Prior to performing any tuning session, the permittee shall provide the Compliance Authority with an advance notice of at least one (1) day that details the activity and proposed tuning schedule, provided excess emissions are anticipated. The notice may be by telephone, facsimile transmittal, or electronic mail."*

3.0 Best Available Control Technology

A detailed BACT analysis for the Project has been included as Appendix D. A summary of the BACT analysis for GEC simple cycle project is provided below:

- Nitrogen oxides (NO_x) emissions-- BACT was determined to be the use of dry low-NO_x (DLN) burners and good combustion controls to achieve 9.0 ppmvd at 15 percent O_2 while firing natural gas. BACT was determined to be the use of DLN and water injection to achieve 42.0 ppmvd at 15 percent O_2 while firing ULSFO.
- Carbon monoxide (CO) emissions-- BACT was determined to be the use of good combustion controls to achieve 4.1 ppmvd at 15 percent O_2 when firing natural gas and 8.0 ppmvd @ 15 percent O_2 when firing ULSFO.
- Particulate (PM/PM_{10}) emissions--BACT was determined to be the use of good combustion controls and firing natural gas or ULSFO.
- Sulfur dioxide (SO_2) emissions--BACT was determined to be the use of natural gas and ULSFO.
- Sulfuric acid mist (H_2SO_4) emissions--BACT was determined to be the use of good combustion controls while firing natural gas and ULSFO.

4.0 Class II Ambient Air Quality Analysis

The following sections discuss the air dispersion modeling methodology and the modeling results from the AAQIA for the proposed Project. This AAQIA has been performed for those emitted criteria pollutants subject to PSD review (PSD applicability based on the combined cycle operation) for which an AAQS exists (i.e., NO_x, PM_{10}, SO_2, and CO). The AAQIA was conducted in accordance with USEPA Guideline on Air Quality Models (incorporated as Appendix W of 40 CFR 51), as well as a mutually agreed upon air dispersion modeling protocol submitted to FDEP on behalf of JEA. The FDEP provided verbal approval of the proposed modeling methodologies during the project kickoff meeting on February 6, 2008 and requested to review a copy of the protocol document. The protocol was subsequently sent to FDEP on February 22, 2008. A copy of the protocol, is presented in Appendix E.

4.1 Class II Model Selection

Consistent with the Appendix W *Guideline on Air Quality Models*, the American Meteorological Society/Environmental Protection Agency (AMS/EPA) Regulatory Model (AERMOD, Version 07026) air dispersion model was used to predict maximum ground-level concentrations associated with the proposed Project's emissions. AERMOD is the product of AMS/EPA Regulatory Model Improvement Committee (AERMIC), formed to introduce state-of-the-art modeling concepts into USEPA's air quality models. AERMOD incorporates air dispersion based on planetary boundary layer turbulence structure and scaling concepts, including treatment of both surface and elevated sources, and both simple and complex terrain. The AERMOD model includes a wide range of options for modeling air quality impacts of pollution sources.

4.2 Model Inputs and Options

This section discusses the model input parameters, source and emission parameters, and the AERMOD model default options and input databases.

4.2.1 Model Input Source Parameters

The AERMOD model was used to determine the maximum predicted ground-level concentration for each pollutant and applicable averaging period resulting from various operating loads, operating scenarios, and ambient temperatures. Performance data for the simple cycle combustion turbines operating at several different loads (50, 75, and 100 percent) over a range of ambient temperatures (7, 59, 68.8, and 105° F) are included in Appendix B. The corresponding stack parameters and emission rates for each load and ambient temperature considered in the analysis are presented in Table 4-1. For all load cases, the parameters in Table 4-1 are "enveloped" over the different operating scenarios as provided in Appendix B. "Enveloping" is the process in which a representative set of stack parameters and pollutant emission rates are utilized to produce the worst-case plume dispersion conditions and highest model predicted concentrations (i.e., lowest exhaust temperature and exit velocity and the highest emission rate).

Emissions from the emergency diesel fire pump, emergency diesel engine generator, and the natural gas heater were also included in the modeling. Manufacturer's specification sheets and the emission calculations for these emission units are included in Appendices B and C, respectively. Emissions from the emergency diesel fire pump and emergency diesel engine generator in the AAQIA are based on each unit operating 24 hours per day, and 400 and 230 hours per year, respectively.

4.2.2 Dispersion Coefficient

With the introduction of AERMOD, the choice of the use of the simple rural or urban dispersion coefficient is no longer available. The AERMOD model has the option of assigning specific sources to have an urban effect, thus enabling AERMOD to employ enhanced turbulent dispersion associated with anthropogenic heat flux, parameterized by population size of the urban area.

Section 8.2.3 of the *Guideline on Air Quality Models* (incorporated as Appendix W of 40 CFR 51) provides the basis for determining the urban/rural status of a source. It was determined that the land use procedure described in Section 8.2.3(c) was sufficient for determining the urban/rural status. The land use procedure is as follows:

- Classify the land use within the total area, A_o, circumscribed by a 3 km radius circle about the source using the meteorological land use typing scheme proposed by Auer.
- If land use Types I1 (heavy industrial), I2 (light-moderate industrial), C1 (commercial), R2 (single-family compact residential), and R3 (multi-family compact residential) account for 50 percent or more of A_o, use urban dispersion coefficients; otherwise, use appropriate rural dispersion coefficients.

Based on a visual inspection of the USGS 7.5-minute topographic map of the proposed site location, it was concluded that over 50 percent of the area surrounding the proposed Project is rural. Since the proposed Project is not located in an urbanized area, urban boundary layer option was not invoked.

Table 4-1
Stack Parameters and Pollutant Emission Rates
Used in AERMOD Modeling Analysis

Period	Source	Load	Stack Height (ft)	Stack Diameter (ft)	Exit Velocity (ft/s)	Exit Temp (°F)	Pollutant Emission Rate (lb/h)			
							NO_x	SO_2	PM/PM_{10}[d]	CO
Annual	CTG[a]	100	115.00	20.00	118.00	1,040.00	42.22	3.60	8.11	N/A
		75	115.00	20.00	102.00	1,118.00	33.91	2.90	8.11	N/A
		50	115.00	20.00	86.00	1,169.00	26.76	2.31	8.11	N/A
	Fire Pump[b]	100	15.17	0.42	286.63	806.00	1.29E-01	1.64E-04	7.40E-03	N/A
	Generator[b]	100	24.00	0.67	528.60	762.80	7.61E-01	5.83E-04	5.25E-03	N/A
	Heater[c]	100	20.00	2.00	7.29	1,165.00	5.50E-01	3.43E-03	4.35E-02	N/A
Short-term	Gas – 24 hours per day									
	CTG[a]	100	115.00	20.00	118.00	1,060.00	N/A	9.01	18.00	17.80
		75	115.00	20.00	102.00	1,118.00	N/A	7.27	18.00	25.30
		50	115.00	20.00	86.00	1,169.00	N/A	5.77	18.00	21.00
	Heater[c]	100	20.00	2.00	7.29	1,165.00	N/A	3.43E-03	4.35E-02	4.60E-01
	Oil – 24 hour per day									
	CTG[a]	100	115.00	20.00	123.00	1,040.00	N/A	2.65	34.00	41.20
		75	115.00	20.00	105.00	1,120.00	N/A	2.12	34.00	55.10
		50	115.00	20.00	88.00	1,170.00	N/A	1.66	34.00	45.00
	Fire Pump[b]	100	15.17	0.42	286.63	806.00	N/A	3.59E-03	1.62E-01	3.70E-01
	Generator[b]	100	24.00	0.67	528.60	762.80	N/A	2.22E-02	2.00E-01	3.95E+00

[a]Emissions for the CTGs are per stack. For the annual modeling scenario, annualized emissions are the higher of the following operating scenarios: 1) 3,500 hours of operation on natural gas; 2) 3,000 hours per year of operation on natural gas with an additional 500 hours per year of operation on ULSFO; or 3) 1,000 hours of operation on ULSFO. When annual emissions are derived from a combination of operation on natural gas and ULSFO, the lowest exit temperature and exit velocity of the two fuels is conservatively assumed. For the short-term modeling scenario, emissions from operation on natural gas and operation on ULSFO were modeled separately since each fuel can be fired for 24-hours per day. CTG emissions given by load are enveloped over several ambient temperatures and modes of operation to produce worst case operation by load. Coordinates for the CTG stacks are as follows: Stack 1 450,218.8 E, 3,336,391.9 N; Stack 2 450,218.8 E, 3,336,445.2 N (Zone 17, NAD 27).
[b]Emissions from these units are based on operation for testing purposes firing ULSFO. As such the emissions for the annual averaging periods are based on 400 hours per year of operation for the fire pump and 230 hours per year for the emergency diesel engine generator. Emissions for the short-term averaging periods are based on 24-hours per day of operation.
[c]Emissions for the natural gas fuel heater are based on 8,760 hours per year of operation and 24-hours per day for short-term operation.
[d]PM/PM_{10} emission rates represent both front and back half emissions.

4.2.3 Good Engineering Practice and Building Downwash Evaluation

The dispersion of a plume can be affected by nearby structures when the stack is short enough to allow the plume to be significantly influenced by surrounding building turbulence. This phenomenon, known as structure-induced downwash, generally results in higher model predicted ground-level concentrations in the vicinity of the influencing structure. Sources included in a PSD permit application are subject to Good Engineering Practice (GEP) stack height requirements outlined in 40 CFR Part 51, Sections 51.100 and 51.118. GEP stack height is defined as the greater of:

1. 65 meters,
2. a height established by applying the formula:

$$Hg = H + 1.5\ L$$

where:

Hg	=	GEP stack height
H	=	height of nearby structure(s)
L	=	lesser dimension (height or projected width) of nearby structure(s)

3. a height demonstrated by a fluid model or a field study which ensures that emissions from a stack do not result in excessive concentrations of any pollutant as a result of atmospheric downwash, wakes, or eddy effects created by the source itself, nearby structures, or nearby terrain features.

Since a fluid model analysis or a field study will not be completed, the GEP stack height is defined by definition 1 or 2. Subsequently, the term *nearby* is defined as a distance up to five times the lesser of the height or width dimension of a structure or terrain feature, but not greater than 800 meters.

For these analyses, the buildings and structures of the proposed simple cycle facility were analyzed to determine the potential to influence the plume dispersion from the combustion turbines and ancillary sources' stacks. Structure dimensions and relative locations were entered into the USEPA's Plume Rise Model Enhancement (PRIME) version of Building Profile Input Program Prime (BPIPPRM, Version 04274) to produce an AERMOD input file with direction specific building downwash parameters. The BPIPPRM formula GEP heights for the CTG stacks are 42.85 m (140.58 ft) for the north stack and 42.84 m (140.55 ft) for the south stack. The proposed CTG stack heights are each 35.05 m (115 ft). As such, direction-specific downwash parameters from the BPIPPRM program were included in the AERMOD air dispersion modeling analysis.

4.2.4 Model Default Options

Since the AERMOD model is especially designed to support the USEPA's regulatory modeling programs, the regulatory modeling options are considered the default mode of operation for the model. These options include the use of stack-tip downwash and a routine for processing averages when calm winds or missing meteorological data occur.

4.2.5 AERMOD Receptor Grid and Terrain Considerations

The air dispersion modeling receptor locations were established at appropriate distances to ensure sufficient density and aerial extent to adequately characterize the pattern of pollutant impacts in the area. Specifically, a nested rectangular grid network that extends out 10 km from the center of the proposed location was used. The nested rectangular grid network consists of four tiers: the first tier extends from the center of the site to 1 km with 100 m spacing; the second tier extends from 1 km to 2.5 km with 250 m spacing; the third tier extends from 2.5 km to 5 km with 500 m spacing; and the fourth tier extends from 5 km to 10 km with 1,000 m spacing. Receptors were placed at 50 m intervals along the property's security boundary (i.e., that area to which public access is physically restricted).

Terrain elevations at receptors were obtained from 7.5-minute United States Geological Survey (USGS) Digital Elevation Model (DEM) files and incorporated into the AERMOD model. There is no distinction in AERMOD between elevated terrain below release height and terrain above release height, as with earlier regulatory models that distinguished between simple terrain and complex terrain. For applications involving elevated terrain, the user must now also input a hill height scale along with the receptor elevation. To facilitate the generation of hill height scales for AERMOD, a terrain preprocessor, called AERMAP, has been developed by USEPA. For each receptor AERMAP searches for the terrain height and location that has the greatest influence on dispersion. In order to calculate the hill height scale, the DEM array and domain boundary must include all terrain features that exceed a 10 percent elevation slope from any given receptor. A visual inspection of the surrounding DEM files was performed to ensure that all such terrain nodes are covered in the computation of the hill height scale. Using AERMAP (Version 06341), terrain elevations were determined using a method that locates interpolated terrain elevation near each receptor. This method ensures that the most representative elevation of the surrounding nearby terrain points in the DEM files are used for each receptor.

4.2.6 Meteorological Data

The AERMOD model utilizes a file of surface boundary layer parameters and a file of profile variables including wind speed, wind direction, and turbulence parameters. These two types of meteorological inputs are generated by the meteorological preprocessor for AERMOD, which is called AERMET (Version 06341). AERMET includes three stages of preprocessing of the meteorological data. The first two stages extract, quality check, and merge the available meteorological data. The third stage requires input of certain surface characteristics (surface roughness, Bowen ratio, and Albedo) from the area of concern.

AERMET requires hourly input of specific surface and upper air meteorological data. These data, at a minimum, include the wind flow vector, wind speed, ambient temperature, cloud cover, and morning radiosonde observation, including height, pressure, and temperature. Surface characteristics in the vicinity of the proposed emissions sources are important in determining the boundary layer parameter estimates. Obstacles to the wind flow, amount of moisture at the surface, and reflectivity of the surface affect the calculations of the boundary layer parameters and are quantified by the following variables: surface roughness length, surface Albedo, and Bowen ratio, respectively.

Representative Hourly Meteorological Data

The *Appendix W – Guideline on Air Quality Models* (November 2005), the *Meteorological Monitoring Guidance for Regulatory Modeling Applications* (EPA-454/R-99-005, Feb 2000), and the *Draft New Source Review Workshop Manual* (October 1990) indicate that when site-specific data are not available, 5 years of *adequately representative* data from a nearby National Weather Service station may be used. The analyses presented herein utilize 5 years (2001-2005) of meteorological data from the Jacksonville International Airport (JAX) as data representative of the Project location.

Representativeness of meteorological data is dependent on the following four factors:

- Spatial--The proximity of the meteorological monitoring site to the area under consideration.
- Temporal--The period of time during which the data is collected.
- Exposure--The siting of the meteorological instruments at the monitoring site.
- Geographic--The geographic features and land use cover in the vicinity of the monitoring site.

Spatial

The spatial representativeness of the meteorological data can be adversely affected by large distances between the source and the monitoring site. As, such, spatial representativeness is best achieved by using meteorological data in close proximity to the area under consideration. JAX is certainly in close proximity to the facility being located only 26 miles north-northwest. Additionally, the elevation of JAX (32 ft) is similar to that of the facility location (30 ft).

Temporal

Temporal representativeness of the meteorological data refers to year-to-year variations or climatological accuracy of the data. The period or record of meteorological data should be sufficient to ensure that the worst-case meteorological dispersion conditions are adequately captured and provide a stable distribution of meteorological conditions. Too short of record may cause excessive variability in the model predicted concentrations.

The *Guideline on Air Quality Models* concludes that the variability of model estimates is adequately reduced if a 5-year period of record of meteorological data is used. The *Draft New Source Review Workshop Manual* indicates that the "5-year period is used to ensure that the model results adequately reflect meteorological conditions conducive to the prediction of maximum ambient concentrations." By using 5 years of meteorological data, the model contains 35,040 more hourly observations with which to predict concentrations than a single year of site-specific observations.

JAX has numerous years of data available for use in air dispersion modeling. The simulations presented here use the 5-year data set from 2001 through 2005 as received by the FDEP for use in air dispersion modeling demonstrations.

Exposure

As given in the document *Meteorological Data Representivity Analysis* (http://www.iowadnr.gov/air/prof/tech/files/representivity_analysis.pdf), produced by the Iowa Department of Natural Resources:

> *Instrument exposure refers to the ability of the instruments to measure meteorological conditions without the influence of manmade or natural obstructions. If obstructions are present, they can influence the measurements of the meteorological monitoring site.*

The meteorological data observations at JAX are derived from an Automated Surface Observing Station (ASOS), which are located at all major airports. The *Federal Standard for Siting Meteorological Sensors at Airports* requires that sensors be installed in appropriate locations to assure that the resultant observations are representative of the meteorological conditions. Because of this, it is determined that instrument exposure does not affect the representativeness of JAX meteorological data.

Geographic

Geographic representativeness refers to the degree surface parameters and characteristics differ between the area of interest and the meteorological monitoring site and can thus influence atmospheric dispersion. The effects of geographic features and land cover on representativeness require a degree of professional judgment. There are no significant geographic terrain features in the area that would greatly influence the wind flow in the area. Additionally, JAX and the facility location are each located in close proximity to the Atlantic Ocean, 16 miles and 9 miles, respectively.

As mentioned previously, geographic representativeness also includes the degree surface parameters and characteristics differ between the area of interest and the meteorological monitoring site. AERMOD uses three landuse-based surface characteristics in its dispersion algorithms: 1) surface roughness (z_o), 2) Bowen ratio (B_o), and 3) albedo (r). The USEPA's *AERMOD Implementation Guide* (updated January 2008) provides a indication of how one may determine representativeness.

> *When using National Weather Service (NWS) data for AERMOD, data representativeness can be thought of in terms of constructing realistic planetary boundary layer (PBL) similarity profiles. As such, the determination of representativeness should include a comparison of the surface characteristics (i.e., z_o, B_o and r) between the NWS measurement site and the source location, coupled with a determination of the importance of those differences relative to predicted concentrations.*

The recently released AERSURFACE tool (Version 08009), was used to process land cover data to determine the surface characteristics for both the facility location and JAX. The results of the AERSURFACE simulation are given below.

Location	Albedo	Bowen Ratio	Surface Roughness
Facility	0.14	0.41	0.61
JAX	0.14	0.48	0.32

Notes:
Potential values range as follows:
1. Albedo: 0.1 – 0.6.
2. Bowen ratio: 0.1 – 6.0.
3. Surface roughness: 0.0001 – 1.3.

Sensitivity runs performed by the USEPA and presented at the 8th Modeling Conference (held September 2005 at Research Triangle Park) demonstrate that resulting model-predicted concentrations from buoyant and very buoyant stacks between 35 and 50 meters in height (similar to the stacks proposed herein) remain nearly flat as the three surface characteristics are altered within their potential range of values. Given the results of the USEPA sensitivity analysis and the fact the resulting values of the three site characteristics lie in close proximity to one another given the range of potential values, the values presented here are in good agreement with one another as to deem JAX representative from a landuse standpoint.

Conclusion

The above demonstration, including the four factor test and a comparison of landuse surface characteristics concludes that the use of existing adequately representative meteorological data from JAX in the AERMOD model is protective of air quality standards (including PSD Increment) and thereby acceptable for use in the AAQIA.

4.3 Model Predicted Impacts

As presented in Section 2.0, the Project's potential future combined cycle PTE exceeds the PSD significant emission thresholds for NO_x, SO_2, PM/PM_{10}, and CO. In accordance with the submitted modeling protocol, AERMOD air dispersion modeling was performed for these pollutants (as described in the preceding sections). Table 4-2 compares the maximum model predicted concentrations for each pollutant and applicable averaging period with the PSD Class II significant impact levels (SILs) and the pre-construction monitoring requirements. As Table 4-2 indicates, the Project's maximum model-predicted concentrations are less than the PSD Class II SILs for each pollutant and applicable averaging period. Therefore, under the PSD program, no further air quality impact analyses (i.e., PSD increment and Ambient Air Quality Standards analyses) are required.

If any of the maximum impact concentrations or concentrations within 10 percent of the maximum impact source groups from each pollutant and averaging period, occurred at the edge of or beyond the 100 m fine grid, a 100 m refined receptor grid was placed around the impact to ensure that an absolute maximum concentration was obtained from the model.

Electronic copies of all Class II modeling input and output files are included in Attachment F.

Table 4-2
AERMOD Model-Predicted Class II Impacts

Pollutant	Fuel	Averaging Period	Model-Predicted Impact[a] ($\mu g/m^3$)			PSD Class II SIL[b] ($\mu g/m^3$)	Exceed SILs?	De Minimis Monitoring Level[c] ($\mu g/m^3$)	Pre-Construction Monitoring Required?
			100%	75%	50%				
NO_x	NG/ULSFO[d]	Annual	0.73	0.73	0.73	1	NO	14	NO
SO_2	NG/ULSFO[d]	Annual	0.01	0.01	0.01	1	NO	--	N/A
	NG	24 Hour	0.22	0.20	0.18	5	NO	13	NO
	ULSFO	24 Hour	0.11	0.11	0.11	5	NO	13	NO
	NG	3 Hour	0.62	0.57	0.52	25	NO	--	N/A
	ULSFO	3 Hour	0.18	0.17	0.15	25	NO	--	N/A
PM/PM_{10}[e]	NG/ULSFO[d]	Annual	0.06	0.06	0.06	1	NO	--	N/A
	NG	24 Hour	4.02	4.02	4.02	5	NO	10	NO
	ULSFO	24 Hour	4.03	4.03	4.03	5	NO	10	NO
CO	NG	8 Hour	16.92	16.93	16.93	500	NO	575	NO
	ULSFO	8 Hour	16.92	16.93	16.93	500	NO	575	NO
	NG	1 Hour	27.56	27.56	27.56	2,000	NO	--	N/A
	ULSFO	1 Hour	26.53	26.53	26.53	2,000	NO	--	N/A

[a]Impacts represent the highest first high model-predicted concentration from all 5 years of meteorological data: 2001, 2002, 2003, 2004, and 2005 modeled at each corresponding load and include operation of the two CTGs, emergency diesel engine generator, fire pump, and natural gas heater.

[b]Predicted impacts that are below the specified level indicate that the proposed project will not have predicted significant impacts for that pollutant and further modeling is not necessary for that pollutant.

[c]This criteria is used to determine if pre-construction ambient air monitoring is required to assess current and future compliance with Ambient Air Quality Standards.

[d]Impacts are from one of the following annual modeling scenarios: 1) 3,500 hours of operation on natural gas; 2) 3,000 hours per year of operation on natural gas with an additional 500 hours per year of operation on ULSFO; or 3) 1,000 hours of operation on ULSFO; whichever scenario produced the higher emissions profile.

[e]Note that the PM_{10} impacts are below the PM_{10} PSD Class II SILs and that the AAQS for $PM_{2.5}$ are significantly greater than the PM_{10} SILs. Therefore, if one were to conservatively assume that $PM_{2.5}$ impacts would be the same as the PM_{10} impacts (in accordance with the USEPA's guidance memorandum related to the interim implementation of NSR for PM 2.5), then the impacts would be significantly below the $PM_{2.5}$ AAQS.

4.3.1 Pre-construction Monitoring

The maximum predicted concentrations presented in Table 4-2 are less than the pre-construction monitoring de minimis levels for each pollutant and applicable averaging period. Therefore, by this application, the applicant requests an exemption from the PSD pre-construction monitoring requirements for NO_x, CO, SO_2, and PM_{10}.

As given in rule 62-212.400(3)(e)1.e, F.A.C., no de minimis air quality level is provided for ozone. According to this rule, an ambient impact analysis and pre-construction ozone monitoring may be required for projects with emissions greater than 100 tpy of either NO_x or VOC. The PTE of VOC emissions are less than 100 tpy, but NO_x emissions are greater than 100 tpy (NO_x emissions will be significantly reduced once the facility is converted to combined cycle operation).

Ozone is a regional issue driven by the interaction of regional emissions sources of NO_x and VOC and those pollutants' reactivity in the presence of sunlight to form ground-level ozone. Ozone predictions are typically made with the use of resource intensive, multi-source, photochemical grid models performed at the research level for air quality planning purposes. Consequently, the use of photochemical models to assess individual point sources has been limited and is not common place.

However, Richard Scheffe developed "VOC/NO_x Point Source Screening Tables" (EPA-OAQPS-TSD-SRAB, 1988) to conservatively estimate ozone increases from individual sources on a short-term basis (based on prior regional reactive gas modeling). According to the documentation, his screening technique has been designed to be both robust and simple to use, while maintaining several inherent assumptions which lead to conservative ozone increment predictions. Scheffe created two separate ozone lookup tables: one for rural areas and one for urban areas. The urban table yields higher ozone estimates and as such was used in this analysis. The urban screening table provides ozone increments as a function of VOC mass emission rates and VOC/NO_x emissions ratios. The urban table estimates that the project could conservatively have a 0.0021 ppm (4.12 $\mu g/m^3$) ozone impact. While no significant impact level (SIL) exists for ozone, the Scheffe estimate is only 2.8 percent of the current 8-hour ozone AAQS and only 1.8 percent of the previous 1-hour ozone AAQS. The SILs for other short-term period PSD pollutants such as CO, SO_2, and PM_{10} average 3.4 percent of their respective AAQS. As presented immediately above, the Scheffe-estimated ozone impact for this project is below the average SIL-to-AAQS ratio of other short-term averaged PSD pollutants. Therefore, it is assumed that the project's contribution to ozone will be insignificant and the applicant requests an exemption from the PSD pre-construction monitoring requirement for ozone.

5.0 Class I Ambient Air Quality Analysis

As part of the air impact evaluation, analyses of the proposed Project's effect on all Class I areas within 300 km were performed. Specifically, Bradwell Bay Wilderness (BBW), Chassahowitzka Wilderness (CW), Okefenokee Wilderness (OW), St. Marks Wilderness (SMW), and Wolf Island Wilderness (WIW) areas are the Class I areas of concern for this project. Federal Class I areas are afforded special environmental protection through the use of Air Quality Related Values (AQRVs). The AQRVs of interest in this analysis are regional haze and deposition. Additionally, Class I SILs were evaluated and compared to the recommended thresholds. Figure 5-1 presents the location of the proposed Project site with respect to the CWA.

The methodology of the refined California Puff (CALPUFF) analysis followed those procedures recommended in the *Interagency Workgroup on Air Quality Modeling (IWAQM) Phase II* report dated December 1998 and the *Phase I Federal Land Managers' Air Quality Related Values Workgroup (FLAG)* report dated December 2000, and an air dispersion modeling protocol sent to FDEP on February 22, 2008 (Appendix E). One refinement was made to the proposed regional haze modeling methodologies since the submittal of the protocol on February 22, 2008. The FDEP was notified of this refinement via phone correspondence on April 2, 2008 and is discussed in detail in this report in Section 5.2.1. The following sections include discussions of the air modeling approach to assess impacts at each of the aforementioned Class I areas, as well as the resulting model-predicted impacts from the Project onto these areas.

5.1 Class I Model Selection and Inputs

5.1.1 Model Selection

The CALPUFF (Version 5.8, Level 070623) air modeling system was used to model the proposed Project and assess the AQRVs at each of the aforementioned Class I areas. CALPUFF is a non-steady state Lagrangian Gaussian puff long-range transport model that includes algorithms for building downwash effects as well as chemical transformations (important for visibility controlling pollutants), and wet/dry deposition. The CALMET model (Version 5.8, Level 070623), a preprocessor to CALPUFF, is a diagnostic meteorological model that produces three-dimensional fields of wind and temperature and two-dimensional fields of other meteorological parameters. CALMET was designed to process raw meteorological, terrain, and land-use databases to be used in the air modeling analysis. However, VISTAS, the Regional Planning Organization responsible for assisting with regional haze issues in the southeast, contracted Earth Tech

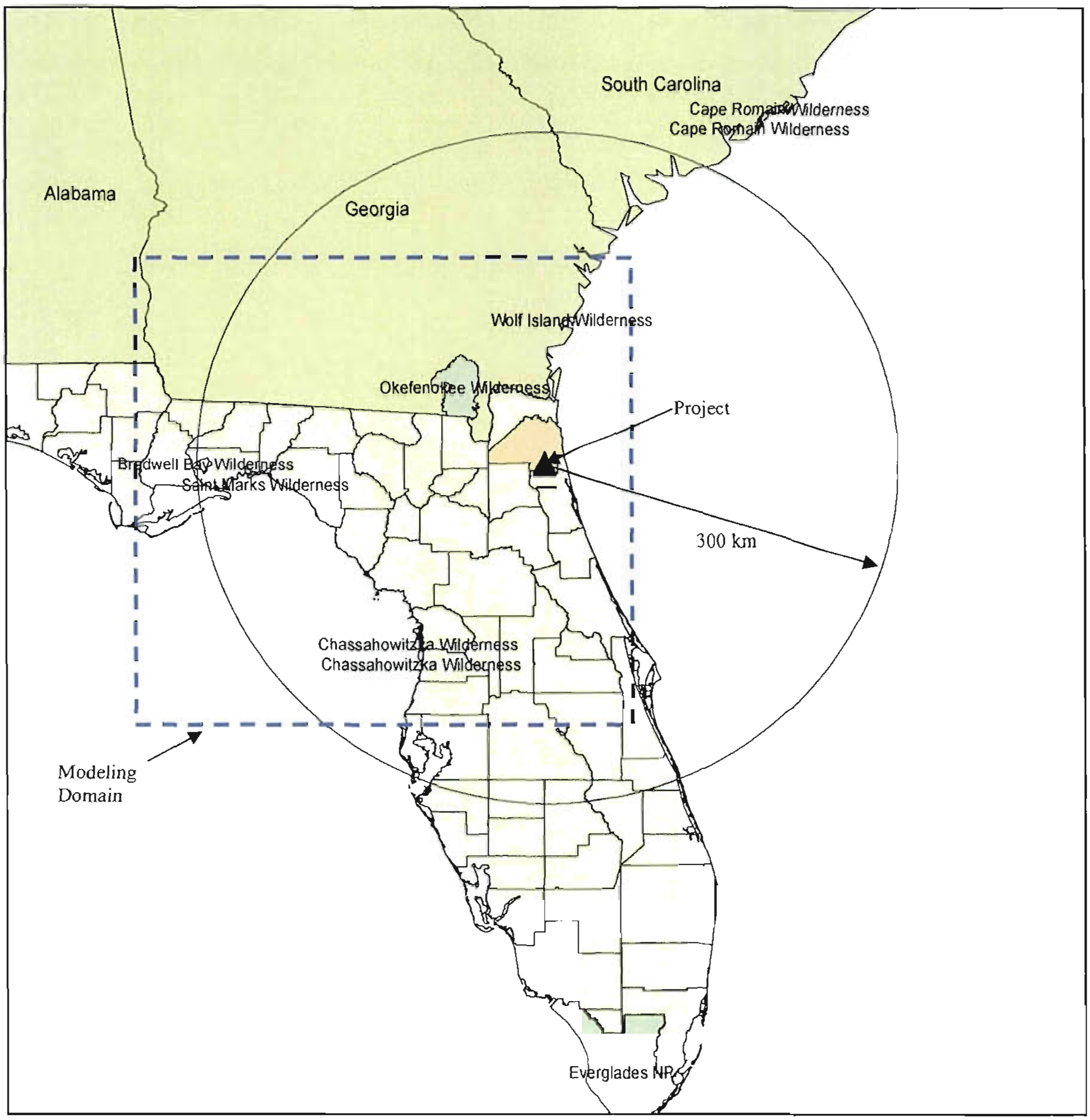

Figure 5-1
Proposed Project Location and Class I Areas

to produce CALPUFF ready, CALMET meteorological data files, thus bypassing the need to run the resources intensive CALMET processor. VISTAS has provided 2001-2003 CALMET files for five 4-km sub-regional domains as illustrated on Figure 5-2. This modeling analysis used the CALMET files prepared for sub-domain 2.

5.1.2 CALPUFF Model Settings

The CALPUFF settings contained in Table 5-1 were used for the modeling analyses.

5.1.3 Building Wake Effects

The CALPUFF analysis included the facility's building dimensions to account for the effects of building-induced downwash on the emission sources. Dimensions for all significant building structures were processed with the USEPA's PRIME version of Building Profile Input Program (BPIPPRM, Version 04274) and included in the CALPUFF model input.

5.1.4 Receptor Locations

The CALPUFF analyses used an array of discrete receptors over the Class I areas, which were created and distributed by the NPS. Specifically, the array consists of receptors spaced to cover the extent of each Class I area. Receptor elevations are included in the same NPS-provided receptor files.

5.1.5 Meteorological Data Processing

The refined 4-km grid resolution VISTAS CALMET files from sub-domain 2 were used as the meteorological and geophysical data for input to CALPUFF. These high resolution, CALPUFF-ready, CALMET files were composed of available surface and upper air observations in addition to the highest resolution MM5 data available for each year (i.e., 12-km MM5 data for 2001 and 2002 and 36-km MM5 data for 2003). A 4-km grid resolution is assumed to be adequate given the lack of significant terrain features in central Florida.

The VISTAS 2001-2003 meteorological data was recently re-processed by the Fish and Wildlife Service (FWS) using the current EPA regulatory version of CALMET (i.e., Version 5.8 Level 070623). Black & Veatch obtained this re-processed fine-grid CALMET dataset for the entire VISTAS region from the North Carolina Department of Environment and Natural Resources.

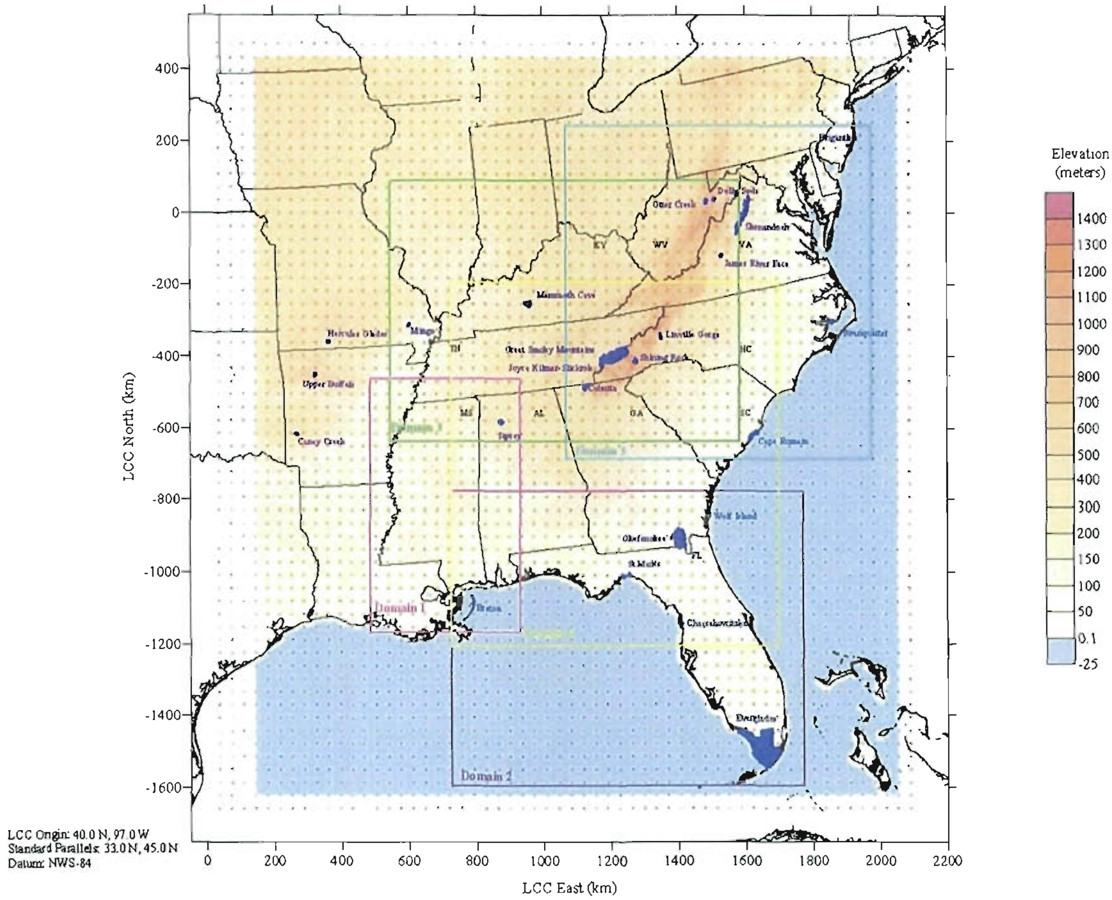

Figure 5-2
VISTAS 4-km CALMET Sub-Domains

Table 5-1
CALPUFF Model Settings

Parameter	**Setting**
Pollutant Species	SO_2, SO_4, NO_x, HNO_3, NO_3, PM_{10}, and speciated particulates.
Chemical Transformation	MESOPUFF II scheme.
Deposition	Include both dry and wet deposition, plume depletion.
Meteorological/Land Use Input	VISTAS CALMET files.
Plume Rise	Transitional plume rise, stack-tip downwash, partial plume penetration.
Dispersion	Puff plume element, PG/MP coefficients, rural ISC mode, PRIME building downwash scheme.
Terrain Effects	Partial plume path adjustment.
Output	Create binary concentration and wet/dry deposition files including output species for all pollutants.
Model Processing	Regional Haze: Highest predicted 24-hour change as processed by CALPOST. Class I SILs: Highest predicted concentrations at the applicable averaging periods for those pollutants that exceed the respective PSD SERs. Deposition: Annual total nitrogen and total sulfur deposition flux (including both wet and dry deposition).
Background Values	Ammonia: 0.5 ppb (monthly). Ozone: Hourly ozone data files provided by TRC for use in VISTAS's BART modeling analyses will be utilized. Monthly values were calculated using monthly averages from Everglades NP, Indian River Lagoon, and the Sumatra ozone monitors. These values are substituted by the CALPUFF model should there be missing hourly values in the VISTAS ozone files.

CALMET Settings

The major features of CALMET used by Earth Tech to develop the CALMET files are listed below:

- Modeling period: 3 years (2001 – 2003).
- Meteorological inputs: MM5 data provide initial guess fields in CALMET. Meteorological observation data are used in the Step 2 calculations. Buoy data, hourly surface meteorological observations, precipitation observations, and twice-daily upper ari sounding data were used.
- CALMET grid resolution: 4 km.
- CALMET vertical layers: 10 layers. Cell face heights (meters): 0, 20, 40, 80, 160, 320, 640, 1200, 2000, 3000, 4000.
- CALMET mode: Refined mode with all available observational data included in the Step 2.
- Diagnostic options: IWAQM default values.
- CALMET options dealing with radius of influence parameters (R1 = 5 km, R2 = 5 km, RMAX1 = 40 km, RMAX2 = 40 km, RMAX3 = 100 km), BIAS(NZ) = 10*0, ICALM = 0 parameters were predetermined by Earth Tech.
- TERRAD (terrain scale) is required for runs with diagnostic terrain adjustments which was used for all years. Value of 15 km used.
- Land use defining water: JWAT1 = 55, JWAT2 = 55 (large bodies of water). This feature allows the temperature field over large bodies of water such as the Atlantic Ocean and the Great Lakes to be properly characterized by buoy observations.
- Mixing height averaging parameter (MNMDAV = 1) was determined by Earth Tech for the regional simulations based on sensitivity tests.
- Geophysical data for regional runs: USGS 3-arcsec terrain data, and Composite Theme Grid USGS 200 m land use dataset.
- References for these and other CALMET datasets can be found on the CALPUFF data page of the official CALPUFF site (www.src.com).

5.1.6 Modeling Domain

The CALPUFF modeling domain was a subset of the larger CALMET meteorological domain. The size of the domain used for the modeling was based on the distances needed to cover the area from the proposed project to the receptors at each of the Class I areas with at least an 80 km buffer zone in each direction. The modeling analysis was performed in the Lambert Conformal Conic (LCC) coordinate system with standard parallels of 33 and 45 degrees north latitude and reference latitude and longitude of 40.0 and 97.0 degrees, respectively. A rectangular modeling domain extending 412 km in the east-west (x) direction and 432 km in the north-south (y) direction was used for the refined modeling analysis. The southwest corner of the domain is located at 1,137.995 km Easting and -1,206 km Northing (LCC, NWS-84, 6,370 km Radius Global Sphere). The grid resolution for the domain was 4 km. A grid spacing of 4 km yields 103 grid cells in the x-direction and 108 grid cells in the y-direction. The size and location of the modeling domain was illustrated on Figure 5-1.

5.1.7 Project Emissions

The worst-case representative stack parameters and pollutants emission rates at 100 percent operating load were used in the CALPUFF analyses. This was accomplished by representing the 100 percent operating load with a worst-case set of stack parameters and pollutant emission rates that were conservatively selected from performance data over a range of ambient temperatures (i.e., 7, 59, 68.8, and 105° F) to produce worst-case plume dispersion conditions (i.e., lowest exhaust temperature and exit velocity and the highest emission rate). This process is referred to as "enveloping."

Those pollutants modeled include NO_x, PM/PM_{10} (filterable and condensable), SO_2, and SO_4 (as H_2SO_4). Table 5-2 contains the stack parameters and emission rates modeled in CALPUFF. Furthermore, in accordance with guidance from NPS, the PM/PM_{10} emissions were speciated based on size and composition for the regional haze analysis and therefore were broken into the following constituents: elemental carbon (EC) and organic carbon (OC) for natural gas operation and EC, Soils, and OC for fuel oil operation. Specifically, guidance from NPS on particulate matter speciation was found in the Emissions & Control Technology area of their Web site. In accordance with NPS, for natural gas fired combustion turbines, all the filterable portion of PM/PM_{10} emissions are considered EC and all non-$(NH_4)_2SO_4$ condensibles are considered to be OC. For fuel oil fired combustion turbines, half of the filterable portion of PM/PM_{10} emissions is considered EC and half is considered Soils and all non-$(NH_4)_2SO_4$ condensibles are considered to be OC.

The EC, OC, and Soils emissions were further speciated based on size. In accordance with NPS guidance, all particles were assumed to be one micron or less for combustion turbines. Tables 5-3, 5-4, and 5-5 present size distribution for EC, OC, and Soils particulates for natural gas operation alone, ULSFO alone, and a combination of natural gas/ULSFO operation, respectively, as recommended by NPS along with the Project's emission rates for each category and size.

Table 5-2
Stack Parameters and Pollutant Emissions
Used in CALPUFF Modeling Analysis

Period	CTG Load[(a)]	Stack Height (ft)	Stack Diameter (ft)	Exit Velocity (ft/s)	Exit Temp (°F)	Pollutant Emission Rate (lb/h)			
						NO_x	PM/PM_{10}[(b)]	SO_2	H_2SO_4[(c)]
Annual[(d)]	100	115	20	118	1,040	42.22	8.11	3.60	1.38
Short-term	**Gas – 24 hours per day[(e)]**								
	100	115	20	118	1,060	64.00	18.00	9.01	3.45
	Oil – 24 hours per day[(f)]								
	100	115	20	123	1,040	355.70	34.00	2.65	1.01
	Oil – 17 hours per day, Gas – 0 hours per day[(g)]								
	100	115	20	123	1,040	252	24.10	1.90	0.70
	Oil – 12 hours per day, Gas – 12 hours per day[(g)]								
	100	115	20	118	1,040	209.85	26.00	5.83	2.23

[(a)]Emissions for the CTGs are per stack. CTG emissions at 100 percent load are enveloped over several ambient temperatures and modes of operation to produce worst case operation for this load. For the annual modeling scenario, annualized emissions are the higher of the following operating scenarios: 1) 3,500 hours of operation on natural gas; 2) 3,000 hours per year of operation on natural gas with an additional 500 hours per year of operation on ULSFO; or 3) 1,000 hours of operation on ULSFO. For the short-term modeling scenarios, several combinations of fuel burning, as required to mitigate model-predicted impacts given in later tables, were modeled. When emissions are derived from a combination of operation on natural gas and ULSFO, the lowest exit temperature and exit velocity of the two fuels is conservatively assumed.
[(b)]PM/PM_{10} emission rates represent both front and back half emissions.
[(c)]Assumes a percentage conversion of SO_2 to SO_3; then 100 percent of SO_3 conversion to H_2SO_4.
[(d)]Annual emissions are used for comparison of impacts to annual Class I SILs and annual Deposition Analysis Thresholds.
[(e)]These short-term emissions are used for comparison of impacts to short-term Class I SILs and Regional Haze for natural gas firing.
[(f)]These short-term emissions are used for comparison of impacts to short-term Class I SILs for ULSFO firing.
[(g)]These short-term emissions are used for comparison of impacts to Regional Haze for ULSFO firing.

Table 5-3
Particle Speciation and Size Distribution for Natural Gas Operation

Species Name	Geometric Mean Diameter (mm)	Size Distribution (%)	Emission Rate (lb/hr)	
			Filterable EC Emissions[a]	Non-$(NH_4)_2SO_4$ Condensable OC Emissions[b]
PM0P05	0.05	15	1.35	1.35
PM0P10	0.10	25	2.25	2.25
PM0P15	0.15	23	2.07	2.07
PM0P20	0.20	15	1.35	1.35
PM0P25	0.25	11	0.99	0.99
PM1P00	1.00	11	0.99	0.99
Subtotals			9.00	9.00
Total			18.00	

[a]Elemental Carbon (EC) includes all filterable emissions.
[b]Organic Carbon (OC) includes all condensable emissions.

Table 5-4
Particle Speciation and Size Distribution for 17 Hours Per Day ULSFO Operation

Species Name	Geometric Mean Diameter (mm)	Size Distribution (%)	Emission Rate (lb/hr)		
			Filterable EC Emissions[a]	Soils[b]	Non-$(NH_4)_2SO_4$ Condensable OC Emissions[c]
PM0P05	0.05	15	0.904	0.904	1.808
PM0P10	0.10	25	1.506	1.506	3.013
PM0P15	0.15	23	1.386	1.386	2.772
PM0P20	0.20	15	0.904	0.904	1.808
PM0P25	0.25	11	0.663	0.663	1.326
PM1P00	1.00	11	0.663	0.663	1.326
Subtotals			6.03	6.03	12.05
Total			24.10		

[a]Elemental Carbon (EC) includes half of filterable emissions.
[b]Soils includes half of filterable emissions.
[c]Organic Carbon (OC) includes all condensable emissions.

Table 5-5
Particle Speciation and Size Distribution for 12 Hours Per Day ULSFO and 12 Hours Per Day Natural Gas Operation

Species Name	Geometric Mean Diameter (mm)	Size Distribution (%)	Emission Rates (lb/hr)							
			ULSFO			Natural Gas		ULSFO/Natural Gas[f]		
			Filterable EC Emissions[a]	Soils[b]	Non-$(NH_4)_2SO_4$ Condensable OC Emissions[c]	Filterable EC Emissions[d]	Non-$(NH_4)_2SO_4$ Condensable OC Emissions[e]	Filterable EC Emissions	Soils	Non-$(NH_4)_2SO_4$ Condensable OC Emissions
PM0P05	0.05	15	0.638	0.638	1.275	0.675	0.675	1.313	0.638	1.950
PM0P10	0.10	25	1.063	1.063	2.125	1.125	1.125	2.188	1.063	3.250
PM0P15	0.15	23	0.978	0.978	1.955	1.035	1.035	2.013	0.978	2.990
PM0P20	0.20	15	0.638	0.638	1.275	0.675	0.675	1.313	0.638	1.950
PM0P25	0.25	11	0.468	0.468	0.935	0.495	0.495	0.963	0.468	1.430
PM1P00	1.00	11	0.468	0.468	0.935	0.495	0.495	0.963	0.468	1.430
Subtotals			4.25	4.25	8.50	4.50	4.50	8.75	4.25	13.00
Total			17.00			9.00		26.00		

[a]For oil firing Elemental Carbon (EC) includes half of filterable emissions.
[b]For oil firing Soils includes half of filterable emissions.
[c]For oil firing Organic Carbon (OC) includes all condensable emissions.
[d]For natural gas firing Elemental Carbon (EC) includes all filterable emissions.
[e]For natural gas firing Organic Carbon (OC) includes all condensable emissions.
[f]Summation of ULSFO firing and natural gas firing speciation values for use in the modeling analyses.

5.2 CALPUFF Analyses Performed

The preceding model inputs and settings for the CALPUFF modeling system were used to complete the Class I analyses at the five Class I areas, including regional haze, deposition, and Class I SILs. Electronic copies of Class I modeling input and output files are included in Attachment F.

5.2.1 Regional Haze Analysis

A regional haze analysis was performed for ammonium sulfates, ammonium nitrates, and particulate matter, by appropriately characterizing model predicted outputs of SO_4, NO_3, and PM_{10} concentrations. PM_{10} emissions were speciated into filterable and condensable PM size categories using NPS speciation spreadsheets.

Visibility

Visibility is an AQRV for all Class I areas except BBW. As such, a visibility analysis was not be performed for BBW. Visibility can take the form of plume blight for nearby areas, or regional haze for long distances (e.g., distances beyond 50 km). Because the each of the Class I areas lie beyond 50 km from the proposed Project, the change in visibility is analyzed as regional haze. Regional haze impairs visibility in all directions over a large area by obscuring the clarity, color, texture, and form of what is seen. Current regional haze guidelines characterize a change in visibility by either of the following methods:

1. Change in the visual range, defined as the greatest distance that a large dark object can be seen, or
2. Change in the light-extinction coefficient (b_{ext}).

Visual range can be related to extinction with the following equation:

$$b_{ext}\,(Mm^{-1}) = 3912 / vr\,(Mm^{-1})$$

Visual range (vr) is a measure of how far away a large black object can be seen in the atmosphere under several severe assumptions including: an absolutely dark target, uniform lighting conditions (cloud free skies), uniform extinction in all directions, a limiting contrast discrimination level, a target high enough in elevation to account for earth curvature, and several other factors. Visual range is, at best, a limited concept that allows relatively simple comparisons between visual air quality levels and should not be thought of as the absolute distance that can be seen through the atmosphere.

The b_{ext} is the attenuation of light per unit distance due to the scattering (light reduced away from the site path) and absorption (light captured by aerosols and turned into heat energy) by gases and particles in the atmosphere. A change in the extinction coefficient produces a perceived visual change that is measured by a visibility index called the deciview. The deciview (dv) is defined as:

$$dv = 10 \ln (1 + b_{exts} / b_{extb})$$

where:

b_{exts} = Extinction coefficient calculated for the source.

b_{extb} = Background extinction coefficient.

A uniform incremental change in b_{extb} or visual range does not necessarily result in uniform changes in perceived visual air quality. In fact, perceived changes in visibility are best related to a percent change in extinction. Based on NPS guidance, if the change in extinction is less than 5 percent, no further analysis is required. An index similar to the deciview that simply quantifies the percent change in visibility due to the operation of a source is calculated as follows:

$$\Delta\% = (b_{exts} / b_{extb}) \times 100$$

Background Visual Ranges and Relative Humidity Factors

The background visual ranges are based on data representative of historical conditions at each of the Class I areas. The background visual ranges, or constituents thereof, for were obtained from the Phase I FLAG Report, December 2000. Relative humidity factors can come from various sources. The average relative humidity factor for each day can be computed by determining the relative humidity factor for each hour's relative humidity for the 24-hour period that the impact occurred. This factor, based on each hour's relative humidity can be obtained by using Table 2.A-1 of Appendix 2.A of the Phase I FLAG Report. These factors (a relative humidity factor for each hour of relative humidity) can then be used to determine the average relative humidity factor for that day (24-hour period). Alternately, the Phase I FLAG report provides seasonal relative humidity factors for each Class I area for direct input to the modeling analyses.

Interagency Workgroup on Air Quality Modeling Guidelines

The CALPUFF air modeling analysis followed the recommendations contained in the IWAQM Phase II Summary Report and Recommendations for Modeling Long Range Transport Impacts, (EPA, 12/98) where appropriate. Table 5-6 summarizes the IWAQM

Phase II recommendations. CALPOST possesses the ability to post-process the modeling results specific to the regional haze analysis through the selection of one of seven modeling options. Specifically, regional haze was first calculated using Method 2, which consists of computing extinctions from speciated PM measurements using hourly relative humidity adjustments for observed and modeled sulfate and nitrates. The relative humidity for Method 2 was capped at 95 percent.

Then, as discussed with the FDEP on April 2, 2008, regional haze impacts were calculated using Method 6, which is similar to Method 2 except that seasonally averaged relative humidity adjustments are uses to compute the resultant extinctions. Method 6 is the preferred method for performing regional haze analyses by all of the regional planning organizations across the country (including VISTAS. which covers the Southeastern states and is the origin of the meteorological database used in these analyses). Additionally, Method 6 is recommended by the USEPA's BART Guidance (70 FR 39162) as the accepted post-processing option. However, unlike the BART guidance and analyses, the results presented herein are conservatively based on the highest maximum model-predicted impacts rather than the 98th percentile impact (i.e., the 8th high impact). While the calculation of regional haze impacts occurs within CALPOST, a typical calculation methodology is illustrated below.

Table 5-6
Outline of IWAQM Refined Modeling Analyses Recommendations

Meteorology	Use CALMET (minimum 6 to 10 layers in the vertical; top layer must extend above the maximum mixing depth expected); horizontal domain extends 50 to 80 km beyond outer receptors and source being modeled; terrain elevation and land-use data is resolved for the situation.
Receptors	Within Class I area(s) of concern; NPS will provide the modeling receptors.
Dispersion	CALPUFF with default dispersion settings. Use MESOPUFF II chemistry with wet and dry deposition. Define background values for ozone and ammonia for area.
Processing	Use highest predicted 24-hr SO_4, PM_{10}, and NO_3 value; calculate extinction coefficients and compute percent change in extinction using the FLAG supplied background extinction where appropriate.

Based on the *IWAQM Phase II Summary Report and Recommendations for Modeling Long Range Transport Impacts* (EPA, 12/98).

Calculation

Refined impacts will be calculated as follows:

1. Obtain 24-hour SO_4, NO_3, and PM speciated (EC, OC, and Soils) impacts, in units of micrograms per cubic meter ($\mu g/m^3$).
2. Convert the SO_4 impact to $(NH_4)_2SO_4$ by the following formula:
   $(NH_4)_2SO_4$ ($\mu g/m^3$) = SO_4 ($\mu g/m^3$) x molecular weight $(NH_4)_2SO_4$ / molecular weight SO_4
   $(NH_4)_2SO_4$ ($\mu g/m^3$) = SO_4 ($\mu g/m^3$) x 132/96 = SO_4 ($\mu g/m^3$) x 1.375
3. Convert the NO_3 impact to NH_4NO_3 by the following formula:
   NH_4NO_3 ($\mu g/m^3$) = NO_3 ($\mu g/m^3$) x molecular weight NH_4NO_3 / molecular weight NO_3
   NH_4NO_3 ($\mu g/m^3$) = NO_3 ($\mu g/m^3$) x 80/62 = NO_3 ($\mu g/m^3$) x 1.29
4. Compute b_{exts} (extinction coefficient calculated for the source) with the following formula:
   $b_{exts} = 3[NH_4NO_3]f(RH) + 3[(NH_4)_2SO_4]f(RH) + 4[OC] + 10[EC] + 4[PMC] + 1[PMF]$
5. Compute b_{extb} (background extinction coefficient) using the background visual range (km) from the FLAG document with the following formula:
   b_{extb} = 3.912 / visual range (km)
6. Compute the change in extinction coefficients:
   in terms of deciviews:
   $dv = 10 \ln (1 + b_{exts} / b_{extb})$
   in terms of percent change of visibility:
   $\Delta\% = (b_{exts} / b_{extb}) \times 100$

Based on the predicted SO_4, NO_3, and speciated PM concentrations, the proposed Project's model-predicted impacts were compared to a 5 percent change in light extinction of the background levels. This is equivalent to a change in deciview of 0.5. As illustrated in Table 5-7, the regional haze results using Method 6 (in conjunction with a reduction in daily hours of oil firing) are less than the 5 percent change in extinction threshold for each of the Class I areas and, as such, no further analysis is necessary. As stated above, the proposed Project is taking a reduction in the amount of daily hours of oil firing allowed in each CTG as a voluntary mitigation measure to ensure that model-predicted impacts from operations do not cause or contribute to degradation in visibility at the nearest Class I areas. Note that all other short-term modeling analyses presented throughout this application support document are conservatively performed without such daily restriction on oil firing as the impacts from the unrestricted daily operation remain below the requisite thresholds.

Table 5-7
Regional Haze Results

Class I Area	Change in Extinction[a] (%)						Recommended Threshold (%)	Method 6 Exceed?
	Method 2			Method 6				
	2001	2002	2003	2001	2002	2003		
Gas – 24 hours per day								
Chassahowitzka	0.83	0.63	0.85	0.57	0.73	0.90	5	NO
Okefenokee	4.56	2.18	2.74	2.99	1.61	1.70	5	NO
St. Marks	0.76	1.49	0.58	0.48	0.86	0.46	5	NO
Wolf Island	1.32	3.21	1.66	0.87	1.78	1.12	5	NO
Oil – 17 hours per day, Gas – 0 hours per day								
Chassahowitzka	2.05	1.15	2.10	1.09	0.91	1.64	5	NO
Okefenokee	10.70	4.79	5.65	4.74	2.17	2.83	5	NO
St. Marks	2.05	3.40	1.31	0.96	1.67	0.93	5	NO
Wolf Island	3.17	8.60	4.00	1.58	4.00	2.00	5	NO
Oil – 12 hours per day, Gas – 12 hours per day								
Chassahowitzka	1.87	1.04	1.94	1.06	1.01	1.61	5	NO
Okefenokee	9.83	4.62	5.41	4.76	2.41	2.86	5	NO
St. Marks	1.75	3.26	1.26	0.87	1.66	0.92	5	NO
Wolf Island	2.87	7.93	3.70	1.53	3.83	1.98	5	NO

[a]Change in extinction was compared against the natural conditions presented in the FLAG 2000 document.

5.2.2 Deposition Analysis

Deposition analyses were performed at each Class I area for both total sulfur and total nitrogen. The analyses followed those procedures and methodologies set forth in the IWAQM Phase II Report and the *Guide for Applying the EPA Class I Screening Methodology with the CALPUFF Modeling System* document, developed by Earth Tech, Inc. (the model developers) in September 2001. This document is a guide for using the POSTUTIL processor to perform deposition analyses. Specifically, deposition analyses were performed as follows:

1. Perform CALPUFF model runs using the specified options previously mentioned in Section 5.1 (including output of both dry and wet deposition).
2. Use POSTUTIL to combine the wet and dry flux output files from CALPUFF and scale the contributions of SO_2, SO_4, NO_x, NO_3, and HNO_3 such that total (i.e., wet and dry) nitrogen and total sulfur flux are contained in the same file. The POSTUTIL file is set up such that SO_2 and SO_4 contribute sulfur mass, and SO_4, NO_x, HNO_3, and NO_3 contribute to the nitrogen mass.
3. Apply the appropriate scaling factors to the CALPOST runs to account for the conversion of grams to kilograms, square meters to hectares (ha), and seconds to a year to achieve CALPOST results in kg/ha/yr.

The model-predicted results were compared to the 0.01 kg/ha/year Deposition Analysis Threshold (DAT) developed jointly by the NPS and the U.S. FWS for Class I areas located east of the Mississippi River. The results of the deposition analysis are presented in Table 5-8. As illustrated in the table, the deposition results for each Class I area are less than the 0.01 DAT and, as such, no further analysis is necessary.

5.2.3 Class I Impact Analysis

Ground-level impacts (in μg/m^3) at each Class I area were calculated for NO_x, SO_2, and PM/PM_{10} criteria pollutants for each applicable averaging period. The results of this analysis were compared with the Class I SILs calculated as 4 percent of the Class I Increment values. Table 5-9 presents the maximum results of the Class I analysis for the 3 year period modeled. As illustrated in the table, there are no impacts above the Class I SILs any of the Class I areas and, as such, no further analysis is necessary.

Table 5-8
Deposition Results

Class I Area	Total Nitrogen Deposition[a] (kg/ha/yr)			Total Sulfur Deposition[b] (kg/ha/yr)			Deposition Analysis Threshold[c]
	2001	2002	2003	2001	2002	2003	
Chassahowitzka	2.01 E-04	2.20 E-04	1.35 E-04	7.38 E-05	8.96 E-05	5.80 E-05	1.0 E-02
Okefenokee	9.26 E-04	1.19 E-03	1.58 E-03	2.22 E-04	3.55 E-04	5.45 E-04	1.0 E-02
St. Marks	2.49 E-04	4.29 E-04	3.85 E-04	8.53 E-05	1.41 E-04	1.39 E-04	1.0 E-02
Wolf Island	4.97 E-04	6.55 E-04	7.29 E-04	2.09 E-04	2.79 E-04	2.75 E-04	1.0 E-02
Bradwell Bay	1.97 E-04	3.30 E-04	2.27 E-04	6.17 E-05	9.84 E-05	8.07 E-05	1.0 E-02

(a)Includes both wet and dry deposition with SO_4, NO_x, HNO_3, and NO_3 contributing to the nitrogen mass.
(b)Includes both wet and dry deposition with SO_2 and SO_4 contributing sulfur mass.
(c)For all areas east of the Mississippi River.

Table 5-9
Class I Significant Impact Levels Modeling Results

Pollutant	Fuel	Averaging Period	Model-Predicted Impact[a] ($\mu g/m^3$)					PSD Class I SIL[b] ($\mu g/m^3$)	Exceed SILs?
			CW	OW	SMW	WIW	BBW		
NO_x	NG/ULSFO[c]	Annual	0.0003	0.0026	0.0004	0.0012	0.0003	0.10	NO
SO_2	NG/ULSFO[c]	Annual	0.0001	0.0003	0.0001	0.0002	0.0001	0.08	NO
	NG	24 Hour	0.0056	0.0206	0.0049	0.0074	0.0041	0.20	NO
	ULSFO	24 Hour	0.0016	0.0060	0.0014	0.0021	0.0012	0.20	NO
	NG	3 Hour	0.0218	0.0425	0.0136	0.0331	0.0095	1.00	NO
	ULSFO	3 Hour	0.0063	0.0126	0.0039	0.0098	0.0027	1.00	NO
PM/PM_{10}	NG/ULSFO[c]	Annual	0.0002	0.0009	0.0003	0.0005	0.0002	0.16	NO
	NG	24 Hour	0.0129	0.0477	0.0136	0.0177	0.0121	0.32	NO
	ULSFO	24 Hour	0.0240	0.0886	0.0255	0.0315	0.0226	0.32	NO

(a)Impacts represent the highest first high model-predicted concentration from all 3 years of meteorological data: 2001, 2002, and 2003 modeled at 100 percent load and include operation of the two CTGs.
(b) Class I SILs are calculated as 4 percent of the PSD Class I Increment values. Predicted impacts that are below the specified levels indicate that the proposed project will not have predicted significant impacts for that pollutant and further modeling is not necessary for that pollutant.
(c) Impacts are from one of the following annual modeling scenarios: 1) 3,500 hours of operation on natural gas; 2) 3,000 hours per year of operation on natural gas with an additional 500 hours per year of operation on ULSFO; or 3) 1,000 hours of operation on ULSFO; whichever scenario produced the higher emissions profile.

6.0 Additional Impact Analysis

A requirement of the PSD regulations is the need for an additional impact analysis as governed by Rule 62-212.400(4)(e), F.A.C., pertaining to the air quality impacts, and the nature and extent of any or all general commercial, residential, industrial, and other growth that has occurred since August 7, 1977, in the area the Project would affect. A characterization of the population trend of the area can be a surrogate for general growth. An evaluation of the growth as it relates to the August 7, 1977 date, as well as a projection of growth indicators related to the Project with respect to workforce, housing, and commercial/industrial growth and their potential impact to air quality are presented below in Sections 6.1 through 6.4.

Additionally, Rule 62-212.400(8)(a), F.A.C., requires that an analysis that considers the impairment to visibility, soils, and vegetation that would occur as a result of the Project be performed. A visibility analysis was performed on five Class I areas and was provided in Section 5.0. Analyses for soils and vegetation were performed and are discussed in Section 6.5.

6.1 Growth Analysis

Jacksonville's current population of 794,555 (U.S Census Bureau 2006 estimate) makes it the largest city in Duval County (which has a total population of 837,964) although it is relatively small when compared to Florida's largest municipalities.

The population trends of Duval County may be used as a surrogate growth indicator of the extent of air quality impacts related to general commercial, residential, and industrial growth since August 7, 1977. The U.S. Census Bureau estimated that Duval County had a population of 559,300 persons in 1977. The Duval County population increased by 33.3 percent between 1977 and 2006, compared to a 50.9 percent growth for Florida over this same time period.

Since 1977, Duval County has successfully balanced growth and economic development with the preservation of unique environmental and recreational areas. The County has anticipated and planned for this additional growth while continuing to demonstrate compliance with the air quality standards (Duval County is in attainment for all criteria pollutants) and preserving the amenities offered to the county population and its visitors. Because the maximum predicted air pollutant concentrations for the proposed Project are well below the NSR/PSD significant impact levels, air concentrations in the region are expected to fully comply with the ambient air quality standards when the proposed Project becomes operational. Therefore, from an air quality impact standpoint, the proposed facility is consistent with the balanced growth demonstrated by the county to date.

6.2 Workforce

Labor force statistics show that as of 2007 Duval County had a total employment of 540,120 persons. Major employment sectors in the county included the trade, transportation, and utilities sector (20.2 percent) as well as the professional and business services sector (15.8 percent). Education and health services (11.3 percent), financial activities (10.4 percent), government (9.6 percent) also made up a significant portion of the Duval County employment by industry in 2007.

County business data for Duval County for 1977 show the total employment to be 222,090 persons. The largest employment sector was in retail trade (18.9 percent). This was followed by government (18.7 percent), the services division (17.6 percent) and the manufacturing industry (12.1 percent). Other major employment sectors in the county included finance, insurance, real estate (11.4 percent), wholesale trade (8.1 percent), transportation, communications, and utilities (7.0 percent), and construction (5.8 percent). Non-classifiable establishments, agriculture, and the mining division make up the remainder of the sectors.

6.2.1 Workforce Growth Associated with the Project

The proposed Project will require a substantial construction workforce during the 18 month construction period, scheduled to span the February 2009 through June 2010 time frame. During this period, an average of 110 direct craft construction workers and a total workforce (that also includes indirect craft workers, construction management, and local utility staff) average of 25 personnel are expected. The peak construction workforce is projected to occur during the 6th month of construction, when 225 direct craft workers, and a total of 250 workers, are expected onsite. However, the construction labor force increase and associated secondary air emissions increase will be temporary and will not result in permanent/significant commercial and residential growth occurring in the vicinity of the proposed Project.

The net number of new, permanent jobs that will be created by GEC is estimated at six. The secondary residential, commercial, and industrial growth associated with this small operation staff, which will be divided into shifts to provide around-the-clock operation, is not expected to have a significant impact on air quality.

6.3 Housing Growth Associated with the Project

The potential for housing shortages and thus the possibility of housing related growth and secondary air quality impacts have been an issue historically for the construction of large coal plants in sparsely populated areas. However, experience has also shown that smaller projects (non-coal plants) like the proposed Project located in or near urban areas typically have no noticeable impacts on the housing market. The reason is that impacts are primarily a function of the size of the construction workforce and the need for the workforce to relocate during construction.

The need to relocate is a function of the available workforce within a reasonable commuting distance of the work site. Research by the Electric Power Research Institute (EPRI) has indicated that the construction workforce for a power plant project can reasonably be expected to commute without relocating during construction from a distance of more than 70 miles, with instances of a commuting distance of more than 100 miles found in each of the construction projects studied. When a 70 mile radius around the GEC site is considered, large metropolitan areas including Jacksonville and Gainesville are within commuting distance to the site, and a 100 mile radius includes cities like Daytona Beach and northern suburbs of Orlando.

The area offers a wide variety of temporary lodging, reflecting the area's status as a destination for recreational seekers. Given the expected population of the commuting workforce, the fact that during the 18 month construction period most workers will be onsite for less than the total construction period, and an abundance of hotel and other short-term lodging options in Duval County, it is unlikely that a substantial number of the construction workforce would choose to relocate during the 18 month construction period. Therefore, the anticipated housing growth will be minimal or nonexistent, and is not expected to have a significant impact on the air quality.

6.4 Commercial/Industrial Growth

The Project is being proposed to meet the existing and current projected electrical demands of the surrounding area. It is anticipated that little commercial growth will be associated with its specific operation. Additionally, the electrical generating capacity created by the CTGs will not have a significant effect upon the industrial growth in the immediate area, considering that the electrical generating capacity will be sold to the grid as opposed to a nearby industrial host. For these reasons, the Project is not expected to have a significant impact on the air quality as the result of commercial or industrial growth.

6.5 Vegetation and Soils Analysis

Combustion turbine projects are typically considered "clean facilities" that have very low predicted ground level pollutant impacts. The low predicted impacts are the direct result of complete combustion and very effective pollutant dispersion. Dispersion is enhanced by the thermal and momentum buoyancy characteristics of the combustion turbine exhaust. Therefore, the Project's impacts on soils and vegetation will be minimal.

The vegetation and soils analysis was based on predicted air pollutant concentrations derived from a comprehensive air dispersion modeling analysis of the CTG stack emissions from the proposed Project. The model-predicted pollutant concentrations were compared to ambient air quality standards, which are designed to protect the public health, welfare, and the natural environment. These ambient air quality standards have been established by the USEPA for the six criteria air pollutants and include primary ambient air quality standards, which are designed to protect public health with an adequate margin of safety, and secondary ambient air quality standards, which are designed to protect public welfare-related values, including property, materials, and plant and animal life. Specifically, and as indicated in the *Draft New Source Review Workshop Manual* (EPA, 1990), ambient concentrations of pollutants below the secondary AAQS will not result in harmful effects for most types of soils and vegetation. In Florida, ambient air quality standards at least as stringent as the national secondary standards have been adopted by the Department.

As given in Section 4.3 of the application, the model-predicted ambient concentrations of SO_2, PM/PM_{10}, NO_x, and CO are not only one or more orders of magnitude less than the applicable ambient air quality standards, but are even less than the more stringent NSR/PSD significant impact levels and the USEPA recommended screening levels for air pollution impacts on plants, soils, and animals. Because the predicted air quality impacts are so much lower than the air quality standards designed to protect plant and animal life, it is reasonable to conclude that the proposed emissions of SO_2, PM/PM_{10}, NO_x, and CO will not significantly affect vegetation, soils, or wildlife.

The air quality impact to soils, vegetation, and wildlife from H_2SO_4 is also expected to be insignificant. There is no national or state air quality standard for H_2SO_4 to compare model-predicted impacts with, as a general measure of H_2SO_4's air quality impact potential, as there are for other PSD pollutants. However, based on the fact that the Project proposes to use two of the least sulfur bearing fuels available (i.e., natural gas and ultra-low sulfur fuel oil) and that predicted SO_2 concentrations are orders of magnitude less than USEPA recommended screening concentrations, it is reasonable to assume that SAM emissions will not significantly impact the air quality in a manner that is detrimental to soils or vegetation.

To further demonstrate that the proposed Project will have an insignificant impact upon vegetation, additional modeling analyses were performed. Those analyses consisted of evaluating the Project's two largest emitted PSD pollutants (NO_x and CO) against the sensitive vegetation thresholds found in the EPA document, *A Screening Procedure for the Impacts of Air Pollution Sources on Plant, Soils, and Animals*. In that document, the minimum NO_2 concentrations at which adverse growth effects or tissue injury occurred for the most sensitive vegetation are: 3,760 ug/m^3 (4 hour averaging period), 564 ug/m^3

(1 month averaging period), and 94 ug/m^3 (1 year averaging period). Similarly, the most sensitive vegetation threshold for CO is given as 1,800,000 ug/m^3 (1 week averaging period); potentially reducing the photosynthetic rate. The model-predicted impacts for these pollutants compared to the given thresholds are presented in Table 6-1. As illustrated in the table the proposed Project's CTG impacts are significantly below the aforementioned screening levels and as such, no adverse impacts to vegetation at or near the facility are expected from NO_x and CO emissions.

The literature about air quality impacts on wildlife generally focuses on acute exposure by wildlife to unusual or high concentrations of pollutants. Wildlife can be affected through three pathways: ingestion, dermal exposure, and inhalation of ambient air, with ingestion, which can result in bioaccumulation, being the most common means of exposure to high concentrations of pollutants. However, the project air emissions and impacts are predicted to be very low, and are highly unlikely to have any effects on wildlife in the vicinity of the project.

Table 6-1
Additional Modeling Results to Assess Impacts to Vegetation

Pollutant	Averaging Period	Model-Predicted Impact[(a)] (ug/m^3)	Screening Threshold[(b)] (ug/m^3)	Exceed Threshold?
NO_x	4-hour	22.33	3.760	No
	24-hour	8.26	564	No
	1-month	1.80	94	No
CO	1-hour	3.60	1,800,000[(c)]	No

[(a)]Impacts represent the highest first high model-predicted concentration from the operation of the CTGs on ULSFO (since ULSFO has the highest short-term emissions for NO_x and CO) for all five years of meteorological data modeled at 100 percent load.
[(b)]Thresholds are taken from EPA document, *A Screening Procedure for the Impacts of Air Pollution Sources on Plant, Soils, and Animals.*
[(c)]Value is actually based on a 1 week averaging period. Model-predicted 1 hour impact is conservatively below this threshold.

Appendix A
FDEP Air Permit Application Forms

Department of Environmental Protection

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Division of Air Resource Management

APPLICATION FOR AIR PERMIT - LONG FORM

I. APPLICATION INFORMATION

Air Construction Permit – Use this form to apply for an air construction permit:

- For any required purpose at a facility operating under a federally enforceable state air operation permit (FESOP) or Title V air operation permit;
- For a proposed project subject to prevention of significant deterioration (PSD) review, nonattainment new source review, or maximum achievable control technology (MACT);
- To assume a restriction on the potential emissions of one or more pollutants to escape a requirement such as PSD review, nonattainment new source review, MACT, or Title V; or
- To establish, revise, or renew a plantwide applicability limit (PAL).

Air Operation Permit – Use this form to apply for:

- An initial federally enforceable state air operation permit (FESOP); or
- An initial, revised, or renewal Title V air operation permit.

To ensure accuracy, please see form instructions.

Identification of Facility

1. Facility Owner/Company Name: JEA	
2. Site Name: Greenland Energy Center	
3. Facility Identification Number: 0310561	
4. Facility Location Street Address or Other Locator: 12121 Philips Hwy City: Jacksonville County: Duval Zip Code: 32258	
5. Relocatable Facility? ☐ Yes ☒ No	6. Existing Title V Permitted Facility? ☐ Yes ☒ No

Application Contact

1. Application Contact Name: N. Bert Gianazza, P.E.
2. Application Contact Mailing Address... Organization/Firm: JEA Street Address: 21 West Church Street City: Jacksonville State: FL Zip Code: 32202-3139
3. Application Contact Telephone Numbers... Telephone: (904) 665-6247 ext. Fax: (904) 665-7376
4. Application Contact Email Address: giannb@jea.com

Application Processing Information (DEP Use)

1. Date of Receipt of Application: 4/21/08	3. PSD Number (if applicable): 401
2. Project Number(s): 0310561-001-AC	4. Siting Number (if applicable):

APPLICATION INFORMATION

Purpose of Application

This application for air permit is submitted to obtain: (Check one)

Air Construction Permit

☒ Air construction permit.

☐ Air construction permit to establish, revise, or renew a plantwide applicability limit (PAL).

☐ Air construction permit to establish, revise, or renew a plantwide applicability limit (PAL), and separate air construction permit to authorize construction or modification of one or more emissions units covered by the PAL.

Air Operation Permit

☐ Initial Title V air operation permit.

☐ Title V air operation permit revision.

☐ Title V air operation permit renewal.

☐ Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is required.

☐ Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is not required.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit (Concurrent Processing)

☐ Air construction permit and Title V permit revision, incorporating the proposed project.

☐ Air construction permit and Title V permit renewal, incorporating the proposed project.

Note: By checking one of the above two boxes, you, the applicant, are requesting concurrent processing pursuant to Rule 62-213.405, F.A.C. In such case, you must also check the following box:

☐ I hereby request that the department waive the processing time requirements of the air construction permit to accommodate the processing time frames of the Title V air operation permit.

Application Comment

This is a construction permit application for a new electric-generating facility (hereinafter referred to as Greenland Energy Center or as GEC) in Jacksonville in Duval County, Florida. The power block at the GEC consists of two General Electric (GE) 7FA-combustion turbine generators (CTGs) operating in simple cycle mode with an exhaust stack for each CTG. The CTGs will have the capability to fire both natural gas and ultra low sulfur fuel oil (ULSFO). Each CTG has a nominal rating of 176 MW while firing natural gas and 190 MW while firing ULSFO, at an ambient temperature of 59°F (ISO condition). This configuration will produce a nominal plant output of 352 MW on natural gas and 380 MW on ULSFO at ISO conditions. In addition to the CTGs, JEA also proposes to install an emergency diesel fire pump, an emergency diesel engine generator, two 1.875 million gallon ULSFO storage tanks and a natural gas fired fuel gas heater.

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Processing Fee
EU01	GE 7FA Simple Cycle Combustion Turbine	AC1A	$7,500
EU02	GE 7FA Simple Cycle Combustion Turbine	AC1A	

Application Processing Fee

Check one: [x] Attached - Amount: $ 7,500 [ ] Not Applicable

APPLICATION INFORMATION

Owner/Authorized Representative Statement

Complete if applying for an air construction permit or an initial FESOP.

1.	Owner/Authorized Representative Name : Mr. James M. Chansler, P.E., D.P.A., Chief Operating Officer
2.	Owner/Authorized Representative Mailing Address... Organization/Firm: JEA Street Address: 21 West Church Street City: Jacksonville State: FL Zip Code: 32202
3.	Owner/Authorized Representative Telephone Numbers... Telephone: (904) 665-4433 ext. Fax: (904) 665-7990
4.	Owner/Authorized Representative Email Address:
5.	Owner/Authorized Representative Statement: *I, the undersigned, am the owner or authorized representative of the corporation, partnership, or other legal entity submitting this air permit application. To the best of my knowledge, the statements made in this application are true, accurate and complete, and any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department.* James M. Chansler Signature Date 4/17/08

APPLICATION INFORMATION

Application Responsible Official Certification

Complete if applying for an initial, revised, or renewal Title V air operation permit or concurrent processing of an air construction permit and revised or renewal Title V air operation permit. If there are multiple responsible officials, the "application responsible official" need not be the "primary responsible official."

1.	Application Responsible Official Name:
2.	Application Responsible Official Qualification (Check one or more of the following options, as applicable): ☐ For a corporation, the president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit under Chapter 62-213, F.A.C. ☐ For a partnership or sole proprietorship, a general partner or the proprietor, respectively. ☐ For a municipality, county, state, federal, or other public agency, either a principal executive officer or ranking elected official. ☐ The designated representative at an Acid Rain source, CAIR source, or Hg Budget source.
3.	Application Responsible Official Mailing Address... Organization/Firm: Street Address: City: State: Zip Code:
4.	Application Responsible Official Telephone Numbers... Telephone: ( ) - ext. Fax: ( ) -
5.	Application Responsible Official E-mail Address:
6.	Application Responsible Official Certification: I, the undersigned, am a responsible official of the Title V source addressed in this air permit application. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof and all other applicable requirements identified in this application to which the Title V source is subject. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department, and I will promptly notify the department upon sale or legal transfer of the facility or any permitted emissions unit. Finally, I certify that the facility and each emissions unit are in compliance with all applicable requirements to which they are subject, except as identified in compliance plan(s) submitted with this application. ________________ ____________ Signature Date

APPLICATION INFORMATION

Professional Engineer Certification

1.	Professional Engineer Name: N. Bert Gianazza Registration Number: 38640
2.	Professional Engineer Mailing Address... Organization/Firm: JEA Street Address: 21 West Church Street City: Jacksonville State: FL Zip Code: 32202
3.	Professional Engineer Telephone Numbers... Telephone: (904) 665-6247 ext. Fax: (904) 665-7376
4.	Professional Engineer Email Address: giannb@jea.com
5.	Professional Engineer Statement:

I, the undersigned, hereby certify, except as particularly noted herein, that:*

(1) To the best of my knowledge, there is reasonable assurance that the air pollutant emissions unit(s) and the air pollution control equipment described in this application for air permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; and

(2) To the best of my knowledge, any emission estimates reported or relied on in this application are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of hazardous air pollutants not regulated for an emissions unit addressed in this application, based solely upon the materials, information and calculations submitted with this application.

(3) If the purpose of this application is to obtain a Title V air operation permit (check here ☐, if so), I further certify that each emissions unit described in this application for air permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance plan and schedule is submitted with this application.

(4) If the purpose of this application is to obtain an air construction permit (check here [x], if so) or concurrently process and obtain an air construction permit and a Title V air operation permit revision or renewal for one or more proposed new or modified emissions units (check here ☐, if so), I further certify that the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.

(5) If the purpose of this application is to obtain an initial air operation permit or operation permit revision or renewal for one or more newly constructed or modified emissions units (check here , if so), I further certify that, with the exception of any changes detailed as part of this application, each such emissions unit has been constructed or modified in substantial accordance with the information given in the corresponding application for air construction permit and with all provisions contained in such permit.

Signature 4/17/08
Date

(seal)

* Attach any exception to certification statement.

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates... Zone 17 East (km) 450.218 North (km) 3336.391		2. Facility Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)	
3. Governmental Facility Code: 4	4. Facility Status Code: C	5. Facility Major Group SIC Code: 49	6. Facility SIC(s): 4911
7. Facility Comment :			

Facility Contact

1. Facility Contact Name: N. Bert Gianazza, P.E. – Environmental Services
2. Facility Contact Mailing Address... Organization/Firm: JEA Street Address: 21 West Church Street City: Jacksonville State: FL Zip Code: 32202
3. Facility Contact Telephone Numbers: Telephone: (904) 665-6247 ext. Fax: (904) 665-7376
4. Facility Contact Email Address: giannb@jea.com

Facility Primary Responsible Official

Complete if an "application responsible official" is identified in Section I. that is not the facility "primary responsible official."

1. Facility Primary Responsible Official Name:
2. Facility Primary Responsible Official Mailing Address... Organization/Firm: Street Address: City: State: Zip Code:
3. Facility Primary Responsible Official Telephone Numbers... Telephone: ( ) - ext. Fax: ( ) -
4. Facility Primary Responsible Official Email Address:

FACILITY INFORMATION

Facility Regulatory Classifications

Check all that would apply *following* completion of all projects and implementation of all other changes proposed in this application for air permit. Refer to instructions to distinguish between a "major source" and a "synthetic minor source."

1. ☐ Small Business Stationary Source	☐ Unknown
2. ☐ Synthetic Non-Title V Source	
3. ☒ Title V Source	
4. ☒ Major Source of Air Pollutants, Other than Hazardous Air Pollutants (HAPs)	
5. ☐ Synthetic Minor Source of Air Pollutants, Other than HAPs	
6. ☐ Major Source of Hazardous Air Pollutants (HAPs)	
7. ☐ Synthetic Minor Source of HAPs	
8. ☒ One or More Emissions Units Subject to NSPS (40 CFR Part 60)	
9. ☐ One or More Emissions Units Subject to Emission Guidelines (40 CFR Part 60)	
10. ☐ One or More Emissions Units Subject to NESHAP (40 CFR Part 61 or Part 63)	
11. ☐ Title V Source Solely by EPA Designation (40 CFR 70.3(a)(5))	
12. Facility Regulatory Classifications Comment:	

FACILITY INFORMATION

List of Pollutants Emitted by Facility

1. Pollutant Emitted	2. Pollutant Classification	3. Emissions Cap [Y or N]?
NOX	A	N
CO	A	N
VOC	B	N
SO2	A	N
PM	A	N
PM10	A	N
SAM	A	N

B. EMISSIONS CAPS

Facility-Wide or Multi-Unit Emissions Caps

1. Pollutant Subject to Emissions Cap	2. Facility Wide Cap [Y or N]? (all units)	3. Emissions Unit ID No.s Under Cap (if not all units)	4. Hourly Cap (lb/hr)	5. Annual Cap (ton/yr)	6. Basis for Emissions Cap

7. Facility-Wide or Multi-Unit Emissions Cap Comment:

C. FACILITY ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Facility Plot Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) [X] Attached, Document ID: Attach. 1 [ ] Previously Submitted, Date:_______
2. Process Flow Diagram(s): (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) [X] Attached, Document ID: Attach. 2 [ ] Previously Submitted, Date:_______
3. Precautions to Prevent Emissions of Unconfined Particulate Matter: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) [X] Attached, Document ID: Attach. 3 [ ] Previously Submitted, Date:_______

Additional Requirements for Air Construction Permit Applications

1. Area Map Showing Facility Location: [x] Attached, Document ID: See Figure 2-1 of Application Support Document
2. Description of Proposed Construction, Modification, or Plantwide Applicability Limit (PAL): [x] Attached, Document ID: See Section 2.0 of the Application Support Document
3. Rule Applicability Analysis: [X] Attached, Document ID: Attach. 4
4. List of Exempt Emissions Units (Rule 62-210.300(3), F.A.C.): [x] Attached, Document ID: Attach 5 [ ] Not Applicable (no exempt units at facility)
5. Fugitive Emissions Identification: [ ] Attached, Document ID:_________ [X] Not Applicable
6. Air Quality Analysis (Rule 62-212.400(7), F.A.C.): [ ] Attached, Document ID: See Section 4, 5, 6 of the Application Support Document
7. Source Impact Analysis (Rule 62-212.400(5), F.A.C.): [ ] Attached, Document ID: See Section 4, 5 and 6 of the Application Support Document
8. Air Quality Impact since 1977 (Rule 62-212.400(4)(e), F.A.C.): [ ] Attached, Document ID: See Section 6 of the Application Support Document
9. Additional Impact Analyses (Rules 62-212.400(8) and 62-212.500(4)(e), F.A.C.): [ ] Attached, Document ID: See Section 6 of the Application Support Document
10. Alternative Analysis Requirement (Rule 62-212.500(4)(g), F.A.C.): [ ] Attached, Document ID:_________ [X] Not Applicable

FACILITY INFORMATION

Additional Requirements for FESOP Applications

1.	List of Exempt Emissions Units (Rule 62-210.300(3)(a) or (b)1., F.A.C.): ☐ Attached, Document ID:________ ☐ Not Applicable (no exempt units at facility)

Additional Requirements for Title V Air Operation Permit Applications

1.	List of Insignificant Activities (Required for initial/renewal applications only): ☐ Attached, Document ID:________ ☐ Not Applicable (revision application)
2.	Identification of Applicable Requirements (Required for initial/renewal applications, and for revision applications if this information would be changed as a result of the revision being sought): ☐ Attached, Document ID:________ ☐ Not Applicable (revision application with no change in applicable requirements)
3.	Compliance Report and Plan (Required for all initial/revision/renewal applications): ☐ Attached, Document ID:________ Note: A compliance plan must be submitted for each emissions unit that is not in compliance with all applicable requirements at the time of application and/or at any time during application processing. The department must be notified of any changes in compliance status during application processing.
4.	List of Equipment/Activities Regulated under Title VI (If applicable, required for initial/renewal applications only): ☐ Attached, Document ID:________ ☐ Equipment/Activities On site but Not Required to be Individually Listed ☐ Not Applicable
5.	Verification of Risk Management Plan Submission to EPA (If applicable, required for initial/renewal applications only) : ☐ Attached, Document ID:__________ ☐ Not Applicable
6.	Requested Changes to Current Title V Air Operation Permit: ☐ Attached, Document ID:________ ☐ Not Applicable

C. FACILITY ADDITIONAL INFORMATION (CONTINUED)

Additional Requirements for Facilities Subject to Acid Rain, CAIR, or Hg Budget Program

1.	Acid Rain Program Forms: Acid Rain Part Application (DEP Form No. 62-210.900(1)(a)): [x] Attached, Document ID: See Attach. 9 [ ] Previously Submitted, Date:_________ [ ] Not Applicable (not an Acid Rain source) Phase II NO_X Averaging Plan (DEP Form No. 62-210.900(1)(a)1.): [ ] Attached, Document ID:_________ [ ] Previously Submitted, Date:_________ [ ] Not Applicable New Unit Exemption (DEP Form No. 62-210.900(1)(a)2.): [ ] Attached, Document ID:_________ [ ] Previously Submitted, Date:_________ [ ] Not Applicable
2.	CAIR Part (DEP Form No. 62-210.900(1)(b)): [x] Attached, Document ID: See Attach. 9 [ ] Previously Submitted, Date:_________ [ ] Not Applicable (not a CAIR source)
3.	Hg Budget Part (DEP Form No. 62-210.900(1)(c)): [x] Attached, Document ID: See Attach. 9 [ ] Previously Submitted, Date:_________ [ ] Not Applicable (not a Hg Budget unit)

Additional Requirements Comment

A CD-ROM with air dispersion modeling files is included in the Application Support Document. Please see Appendix G of the application package.

III. EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Application - For Title V air operation permitting only, emissions units are classified as regulated, unregulated, or insignificant. If this is an application for Title V air operation permit, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each regulated and unregulated emissions unit addressed in this application for air permit. Some of the subsections comprising the Emissions Unit Information Section of the form are optional for unregulated emissions units. Each such subsection is appropriately marked. Insignificant emissions units are required to be listed at Section II, Subsection C.

Air Construction Permit or FESOP Application - For air construction permitting or federally enforceable state air operation permitting, emissions units are classified as either subject to air permitting or exempt from air permitting. The concept of an "unregulated emissions unit" does not apply. If this is an application for air construction permit or FESOP, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air permitting are required to be listed at Section II, Subsection C.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit Application – Where this application is used to apply for both an air construction permit and a revised/renewal Title V air operation permit, each emissions unit is classified as either subject to air permitting or exempt from air permitting for air construction permitting purposes and as regulated, unregulated, or insignificant for Title V air operation permitting purposes. **The air construction permitting classification must be used to complete the Emissions Unit Information Section of this application for air permit.** A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air construction permitting and insignificant emissions units are required to be listed at Section II, Subsection C.

If submitting the application form in hard copy, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application must be indicated in the space provided at the top of each page.

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

☐ The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

☐ The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one)

☐ This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

[x] This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

☐ This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Description of Emissions Unit Addressed in this Section:
Natural Gas/Ultra-Low Sulfur Fuel Oil fired Combustion Turbine Units 1 and 2; Each CTG has a nominal rating of 176 MW while firing natural gas and 190 MW while firing ultra low sulfur fuel oil (ULSFO), at an ambient temperature of 59°F (ISO conditions)

3. Emissions Unit Identification Number:

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C			49	[x] Yes ☐ No

9. Package Unit:
Manufacturer: General Electric Model Number: PG7241 7FA

10. Generator Nameplate Rating: 176 MW while firing natural gas and 190 MW while firing ULSFO at ISO conditions

11. Emissions Unit Comment:

Emissions Unit Control Equipment

1. Control Equipment/Methods Description: Dry low NO_x(DLN) burners used to control NO_x when firing natural gas. DLN burners and Water injection used to control NO_x when firing ULSFO.
2. Control Device or Method Code(s): 205, 028

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. *Maximum Process or Throughput Rate:*
2. Maximum Production Rate:
3. Maximum Heat Input Rate: 1,977 (HHV) million Btu/hr (Natural gas, 100% load, 7 °F) 2,153 (HHV) million Btu/hr (ULSFO, 100% load, 7 °F)
4. Maximum Incineration Rate: pounds/hr tons/day
5. Requested Maximum Operating Schedule: A. **Pre-onsite natural gas pipeline:** Each CTG will operate no more than 1,000 hours per year per CTG on ULSFO. This translates to a requested ULSFO usage limit of 30,213 kgal/yr for the two CTGs combined. B: **Post-onsite natural gas pipeline:** The two CTGs will function as peaking units and will each operate no more than 3,500 hours per year, with up to 500 hours of that total on ULSFO, and the balance on natural gas.
6. Operating Capacity/Schedule Comment: The two simple cycle combustion turbines will be operated between 50 and 100 percent of full load. The maximum heat input shown in Field 3 is with operation at 100 percent load at the site minimum ambient temperature of 7°F. Operation at 100 percent load and at 59°F is expected to have a corresponding maximum heat input of 1,806 MBtu/hr and 1,994 MBtu/hr (HHV) for natural gas and ULSFO, respectively. Note that the heat input rates are a function of operating parameters and ambient conditions.

C. EMISSION POINT (STACK/VENT) INFORMATION
(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: Combustion Turbine No. 1 and Combustion Turbine No. 2	2. Emission Point Type Code: 1
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: Each combustion turbine discharges through a 115-foot vertical cylindrical exhaust stack.	
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: N/A	

5. Discharge Type Code: V	6. Stack Height: 115 feet	7. Exit Diameter: 20.0 feet
8. Exit Temperature: (ISO) 1,111 °F (natural gas); 1,094 °F (ULSFO)	9. Actual Volumetric Flow Rate: 2,428,785 acfm (natural gas, ISO) 2,527,700 acfm (ULSFO, ISO)	10. Water Vapor: %

11. Maximum Dry Standard Flow Rate:	12. Nonstack Emission Point Height:
13. Emission Point UTM Coordinates... Zone: 17 East (km): 450.218 North (km): 3336.445	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment: Exit temperature and flow rate are with operation of each combustion turbine at 100 percent load and at ISO conditions.	

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 3

1. Segment Description (Process/Fuel Type): ULSFO used in each of the two combustion turbines (pre-onsite natural gas availability).		
2. Source Classification Code (SCC): 2-01-001-01	3. SCC Units: Thousand Gallons Burned	
4. Maximum Hourly Rate: 16.3	5. Maximum Annual Rate: 15,106 per CTG	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: 0.0015	8. Maximum % Ash:	9. Million Btu per SCC Unit: 132 (HHV)

10. Segment Comment:

Approximate fuel use rate calculations:
(heat input at HHV)/(fuel HHV) = hourly rate

Maximum Hourly Rate:
(2,153 MBtu/hr)/(132 MBtu/kgal) = 16.3 kgal/hour **per CTG**

Maximum Annual Rate:
[(1,994 MBtu/hr)/(132 MBtu/kgal)]x(1,000 hr/yr x 2) = 30,213 kgal/yr **(two CTGs combined)**

Maximum hourly rate is based on operation at 7°F ambient temperature and maximum annual rate based on operations at 59°F ambient temperature. The two CTGs will function as peaking units and will each operate no more than 1,000 hours per year per unit on ULSFO prior to the installation of the natural gas pipeline to the proposed site.

It is requested that for the pre-onsite natural gas pipeline scenario, the CTGs be limited to a combined ULSFO usage of 30,213 kgal/yr instead of an hourly operational limit. Please see Section 5.0 of the application support document for daily ULSFO restrictions for compliance with regional haze impact thresholds.

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 2 of 3

1. Segment Description (Process/Fuel Type): Natural gas used in each of the two combustion turbines (post-onsite natural gas availability)		
2. Source Classification Code (SCC): 2-01-002-01	3. SCC Units: Million Cubic Feet Burned	
4. Maximum Hourly Rate: 2.02 (approx.)	5. Maximum Annual Rate: 6,464 per CTG	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: 978 (HHV)

10. Segment Comment:

Approximate fuel use rate calculations:
(heat input at HHV)/(fuel HHV) = hourly rate

Maximum Hourly Rate:
(1,977 MBtu/hr)/(978 MBtu/million scf) = 2.02 million scf/hour **per CTG**

Maximum Annual Rate:
[(1,806 MBtu/hr)/(978 MBtu/million scf)]x(3,500 hr/yr x 2) = 12,927 million scf/yr **(two CTGs combined)**

Maximum hourly rate is based on operation at 7°F ambient temperature and maximum annual rate based on operations at 59°F ambient temperature and 3,500 hours of natural gas firing in each of the two combustion turbines.

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 3 of 3

1. Segment Description (Process/Fuel Type): ULSFO used in each of the two combustion turbines (post-onsite natural gas availability).		
2. Source Classification Code (SCC): 2-01-001-01	3. SCC Units: Thousand Gallons Burned	
4. Maximum Hourly Rate: 16.3	5. Maximum Annual Rate: 7,553 per CTG	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: 0.0015	8. Maximum % Ash:	9. Million Btu per SCC Unit: 132 (HHV)

10. Segment Comment:

Approximate fuel use rate calculations:
(heat input at HHV)/(fuel HHV) = hourly rate

Maximum Hourly Rate:
(2,153 MBtu/hr)/(132 MBtu/kgal) = 16.3 kgal/hour **per CTG**

Maximum Annual Rate:
[(1,994 MBtu/hr)/(132 MBtu/kgal)]x(500 hr/yr x 2) = 15,106 kgal/yr **(two CTGs combined)**

Maximum hourly rate is based on operation at 7°F ambient temperature and maximum annual rate based on operations at 59°F ambient temperature. In the post-onsite natural gas pipeline scenario, the two CTGs can each operate 3,500 hours, with up to 500 hours of that total on ULSFO and the balance on natural gas.

Please see Section 5.0 of the application support document for daily ULSFO restrictions for compliance with regional haze impact thresholds.

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
NOX	**205**	**028** (only while firing ULSFO)	**EL**
CO			
VOC			
SO2			**WP**
PM			
PM10			
SAM			

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: NOX	2. Total Percent Efficiency of Control:
3. Potential Emissions: See Appendix C of the application support document for emission calculations	4. Synthetically Limited? [x] Yes [ ] No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code: 5
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: [ ] 5 years [ ] 10 years
10. Calculation of Emissions: See Appendix C of the Application Support Document	
11. Potential, Fugitive, and Actual Emissions Comment: The potential hourly and annual emissions are for informational purposes only and do not constitute limits.	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 5

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 15.0 ppmvd	4. Equivalent Allowable Emissions: 64 lb/hour per CTG (natural gas operation)
5. Method of Compliance: CEMS, 30-day rolling average	
6. Allowable Emissions Comment (Description of Operating Method): The allowable emissions level in Field 3 is from NSPS Subpart KKKK and applies when each CTG is operating on natural gas at greater than 75 percent load. Equivalent allowable emissions are based on operation at 7°F ambient temperature and are included for informational purposes only and do not constitute permit limits.	

Allowable Emissions Allowable Emissions 2 of 5

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 42.0 ppmvd	4. Equivalent Allowable Emissions: 355.7 lb/hour (ULSFO)
5. Method of Compliance: CEMS, 30-day rolling average	
6. Allowable Emissions Comment (Description of Operating Method): The allowable emissions level in Field 3 is from NSPS Subpart KKKK and applies when each CTG is operating on fuel oil at greater than 75 percent load. Equivalent allowable emissions are based on operation at 7°F ambient temperature and are included for informational purposes only and do not constitute permit limits.	

Allowable Emissions Allowable Emissions 3 of 5

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 96 ppmvd	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: CEMS, 30-day rolling average	
6. Allowable Emissions Comment (Description of Operating Method): The allowable emissions level in Field 3 is from NSPS Subpart KKKK and applies when each CTG is operating at less than 75 percent load.	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 4 of 5

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 9.0 ppmvd @ 15 percent O_2	4. Equivalent Allowable Emissions: 58.5 lb/hour per CTG (natural gas operation)
5. Method of Compliance: CEMS, 24-hour block average; Stack test 3-run average	
6. Allowable Emissions Comment (Description of Operating Method): The allowable emissions level in Field 3 is based on the BACT Analysis and applies when each CTG is operating on natural gas. Equivalent allowable emissions are based on operation at 100 percent load and ISO conditions, and are included for informational purposes only and do not constitute permit limits.	

Allowable Emissions Allowable Emissions 5 of 5

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 42.0 ppmvd @ 15 percent O_2	4. Equivalent Allowable Emissions: 329.4 lb/hour (ULSFO)
5. Method of Compliance: CEMS, 24-hour block average; Stack test, 3-run average	
6. Allowable Emissions Comment (Description of Operating Method): The allowable emissions level in Field 3 is based on the BACT Analysis and applies when each CTG is operating on ULSFO. Equivalent allowable emissions are based on operation at 100 percent load and ISO conditions, and are included for informational purposes only and do not constitute permit limits.	

Allowable Emissions Allowable Emissions of _

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: CO	2. Total Percent Efficiency of Control:
3. Potential Emissions: See Appendix C of the Application Support Document	4. Synthetically Limited? [x] Yes [ ] No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code: 5
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: [ ] 5 years [ ] 10 years
10. Calculation of Emissions: See Appendix C of the Application Support Document	
11. Potential, Fugitive, and Actual Emissions Comment: The potential hourly and annual emissions are for informational purposes only and do not constitute limits.	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 4.1 ppmvd @ 15 percent O_2	4. Equivalent Allowable Emissions: 16.2 lb/hour
5. Method of Compliance: CEMS, 24-hour block average; stack test, 3-run average	
6. Allowable Emissions Comment (Description of Operating Method): The allowable emissions level in Field 3 is based on the BACT Analysis and applies when each CTG is operating on natural gas. Equivalent allowable emissions are based on operation at 100 percent load and ISO conditions, and are included for informational purposes only and do not constitute permit limits.	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 8.0 ppmvd @ 15 percent O_2	4. Equivalent Allowable Emissions: 38.2 lb/hour
5. Method of Compliance: CEMS, 24-hour block average; stack test, 3-run average	
6. Allowable Emissions Comment (Description of Operating Method): The allowable emissions level in Field 3 is based on the BACT Analysis and applies when each CTG is operating on ULSFO. Equivalent allowable emissions are based on operation at 100 percent load and ISO conditions, and are included for informational purposes only and do not constitute permit limits.	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: PM/PM10	2. Total Percent Efficiency of Control:
3. Potential Emissions: See Appendix C of the Application Support Document	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code: 5
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: See Appendix C of the Application Support Document	
11. Potential, Fugitive, and Actual Emissions Comment: The potential hourly and annual emissions are for informational purposes only and do not constitute limits.	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 10 percent opacity	4. Equivalent Allowable Emissions: 18 lb/hour (natural gas combustion)
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method): The allowable emissions level in Field 3 is based on the BACT Analysis and applies when each CTG is operating on natural gas. Equivalent allowable emissions are based on operation at 100 percent load and ISO conditions, and are included for informational purposes only and do not constitute permit limits.	

Allowable Emissions Allowable Emissions _ of _

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 10 percent opacity	4. Equivalent Allowable Emissions: 34 lb/hour (ULSFO)
5. Method of Compliance: Annual Visible Emissions Test Using USEPA Method 9, when firing ULSFO	
6. Allowable Emissions Comment (Description of Operating Method): The allowable emissions level in Field 3 is based on the BACT Analysis and applies when each CTG is operating on ULSFO. Equivalent allowable emissions are based on operation at 100 percent load and ISO conditions, and are included for informational purposes only and do not constitute permit limits.	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: SO2	2. Total Percent Efficiency of Control:
3. Potential Emissions: See Appendix C of the Application Support Document	4. Synthetically Limited? [x] Yes [ ] No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code: 5
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: [ ] 5 years [ ] 10 years
10. Calculation of Emissions: See Appendix C of the Application Support Document	
11. Potential, Fugitive, and Actual Emissions Comment: The potential hourly and annual emissions are for informational purposes only and do not constitute limits.	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: Use of natural gas with less than 20 grains sulfur per 100 standard cubic feet	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: Natural gas supplier tariff sheet	
6. Allowable Emissions Comment (Description of Operating Method): The natural gas sulfur standard is associated with NSPS Subpart KKKK. Per 40 CFR 60.4365, JEA is requesting that they be exempt from the requirement to monitor fuel sulfur content by demonstrating the fuel sulfur content through the natural gas tariff sheet.	

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 0.05% sulfur, by weight, in the fuel oil	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: ULSFO purchase contract	
6. Allowable Emissions Comment (Description of Operating Method): The fuel oil sulfur standard is associated with NSPS Subpart KKKK. Per 40 CFR 60.4365, JEA is requesting that they be exempt from the requirement to monitor fuel sulfur content by demonstrating the fuel sulfur content through the fuel oil purchase contract.	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 0.0015 percent sulfur content by weight	4. Equivalent Allowable Emissions: 2.45 lb/hour
5. Method of Compliance: ULSFO purchase contract	
6. Allowable Emissions Comment (Description of Operating Method): The allowable emissions level in Field 3 is based on the BACT Analysis and applies when each CTG is operating on ULSFO. Equivalent allowable emissions are based on operation at 100 percent load and ISO conditions, and are included for informational purposes only and do not constitute permit limits.	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions
Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: VOC	2. Total Percent Efficiency of Control:
3. Potential Emissions: See Appendix C of the Application Support Document	4. Synthetically Limited? [x] Yes [ ] No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code: 5
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: [ ] 5 years [ ] 10 years
10. Calculation of Emissions: See Appendix C of the Application Support Document	
11. Potential, Fugitive, and Actual Emissions Comment: The potential annual emissions are for informational purposes only and do not constitute limits.	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions _ of _

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _ of _

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _ of _

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: SAM	2. Total Percent Efficiency of Control:
3. Potential Emissions: See Appendix C of the Application Support Document	4. Synthetically Limited? [x] Yes [ ] No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code: 5
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: [ ] 5 years [ ] 10 years
10. Calculation of Emissions: See Appendix C of the Application Support Document	
11. Potential, Fugitive, and Actual Emissions Comment: The potential annual emissions are for informational purposes only and do not constitute limits.	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: Natural gas with 2 grains per 100 scf	4. Equivalent Allowable Emissions: 3.15 lb/hour
5. Method of Compliance: Natural gas supplier tariff sheet	
6. Allowable Emissions Comment (Description of Operating Method): The allowable emissions level in Field 3 is based on the BACT Analysis and applies when each CTG is operating on natural gas. Equivalent allowable emissions are based on operation at 100 percent load and ISO conditions, and are included for informational purposes only and do not constitute permit limits.	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 0.0015 percent sulfur in ULSFO	4. Equivalent Allowable Emissions: 0.94 lb/hour
5. Method of Compliance: ULSFO purchase contract	
6. Allowable Emissions Comment (Description of Operating Method): The allowable emissions level in Field 3 is based on the BACT Analysis and applies when each CTG is operating on ULSFO. Equivalent allowable emissions are based on operation at 100 percent load and ISO conditions, and are included for informational purposes only and do not constitute permit limits.	

G. VISIBLE EMISSIONS INFORMATION

Complete Subsection G if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation _ of _

1. Visible Emissions Subtype: VE10	2. Basis for Allowable Opacity: ☐ Rule ☒ Other
3. Allowable Opacity: Normal Conditions: 10 % Exceptional Conditions: Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: Annual USEPA Method 9 test	
5. Visible Emissions Comment: Proposed as PM BACT	

Visible Emissions Limitation: Visible Emissions Limitation ___ of __

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

H. CONTINUOUS MONITOR INFORMATION

Complete Subsection H if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor 1 of 2

1. Parameter Code: EM	2. Pollutant(s): NOX
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information... Manufacturer: TBD Model Number: TBD	Serial Number: TBD
5. Installation Date: TBD	6. Performance Specification Test Date: TBD
7. Continuous Monitor Comment: Rule: 40 CFR 60 and 40 CFR Part 75.	

Continuous Monitoring System: Continuous Monitor 2 of 2

1. Parameter Code: EM	2. Pollutant(s): CO
3. CMS Requirement:	[ ] Rule [X] Other
4. Monitor Information... Manufacturer: TBD Model Number: TBD	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: Needed for compliance with CO BACT limit.	

H. CONTINUOUS MONITOR INFORMATION (CONTINUED)

Complete Subsection H if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor __ of __

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

Continuous Monitoring System: Continuous Monitor ___ of ___

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
[X] Attached, Document ID: Attach. 2 [ ] Previously Submitted, Date ________

2. Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
[X] Attached, Document ID: Attach. 6 [ ] Previously Submitted, Date ________

3. Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
[ ] Attached, Document ID: See Section 3 of the Application Support Document

4. Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
[ ] Attached, Document ID: ________ [ ] Previously Submitted, Date ________
[x] Not Applicable (construction application)

5. Operation and Maintenance Plan (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
[X] Attached, Document ID: Attach. 7 [ ] Previously Submitted, Date ________
[ ] Not Applicable

6. Compliance Demonstration Reports/Records
[ ] Attached, Document ID: ________
Test Date(s)/Pollutant(s) Tested: ________________

[ ] Previously Submitted, Date: ________
Test Date(s)/Pollutant(s) Tested: ________________

[ ] To be Submitted, Date (if known): ________
Test Date(s)/Pollutant(s) Tested: ________________

[X] Not Applicable

Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.

7. Other Information Required by Rule or Statute
[ ] Attached, Document ID: ________ [X] Not Applicable

Additional Requirements for Air Construction Permit Applications

1.	Control Technology Review and Analysis (Rules 62-212.400(10) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)) [x] Attached, Document ID: See Section 3 of the Application Support Document
2.	Good Engineering Practice Stack Height Analysis (Rule 62-212.400(4)(d), F.A.C., and Rule 62-212.500(4)(f), F.A.C.) [x] Attached, Document ID: See Section 4 of the Application Support Document
3.	Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only) [x] Attached, Document ID: See Attach. 8 [ ] Not Applicable

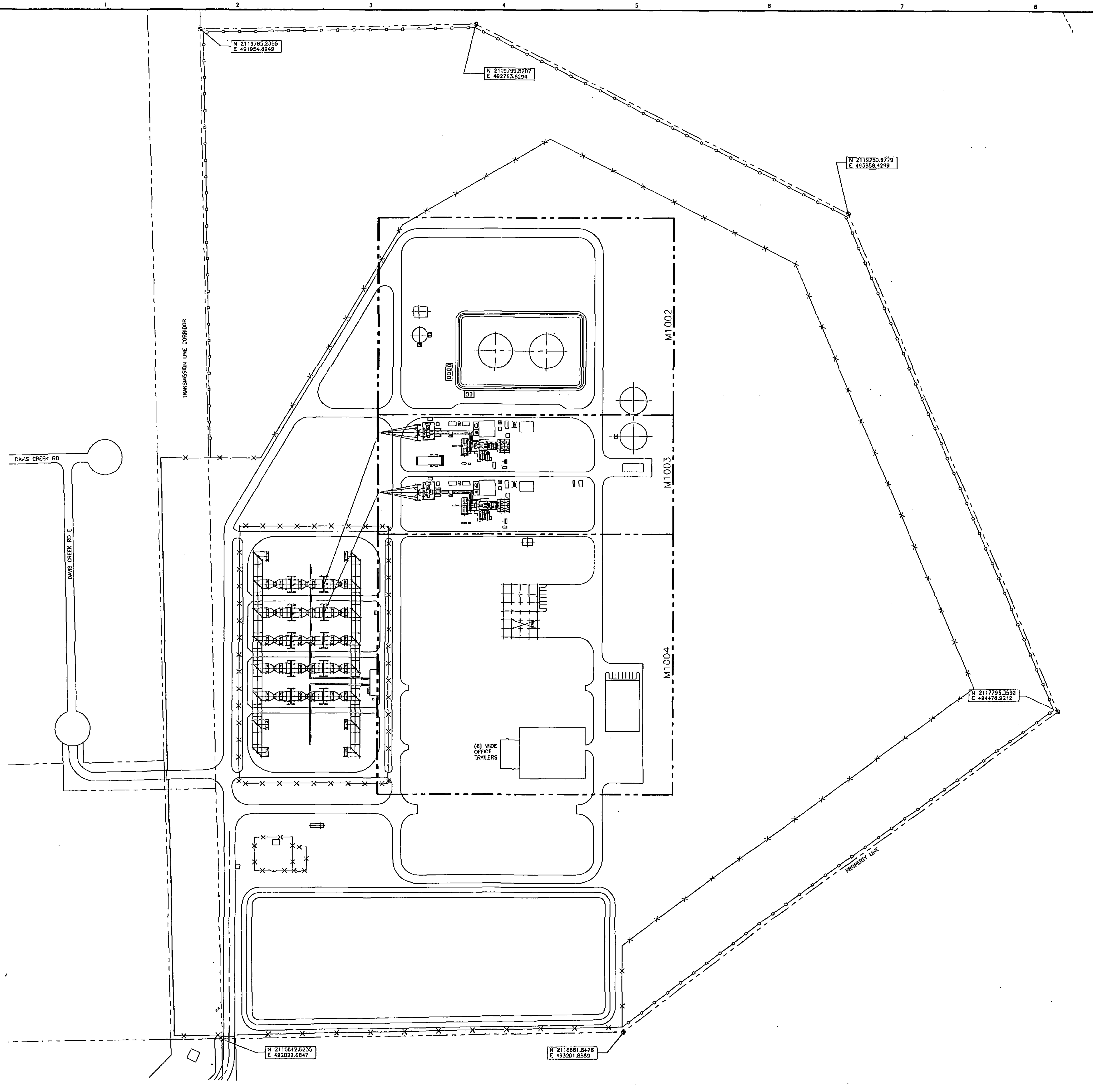
Additional Requirements for Title V Air Operation Permit Applications

1.	Identification of Applicable Requirements: [ ] Attached, Document ID: ______
2.	Compliance Assurance Monitoring: [ ] Attached, Document ID: ______ [ ] Not Applicable
3.	Alternative Methods of Operation: [ ] Attached, Document ID: ______ [ ] Not Applicable
4.	Alternative Modes of Operation (Emissions Trading): [ ] Attached, Document ID: ______ [ ] Not Applicable

Additional Requirements Comment

A CD-ROM with air dispersion modeling files is included in Appendix G of the application package.

Attachment 1
Facility Plot Plan



NOTES

1. NOTE

NOT TO BE USED
FOR CONSTRUCTION

A		INITIAL ISSUE	DS	DS		TD	
NO	DATE	REVISIONS AND RECORD OF ISSUE	DRN	DES	CHK	PDE	APP

100' 50' 0 100' 200'
1"=100'

I HEREBY CERTIFY THAT THIS DOCUMENT WAS PREPARED BY ME OR UNDER MY DIRECT SUPERVISION AND THAT I AM A DULY REGISTERED PROFESSIONAL ENGINEER UNDER THE LAWS OF THE STATE OF FLORIDA

SIGNED ______
DATE ______ REG NO. ______

BLACK & VEATCH

ENGINEER TPD | DRAWN DAS
CHECKED | DATE

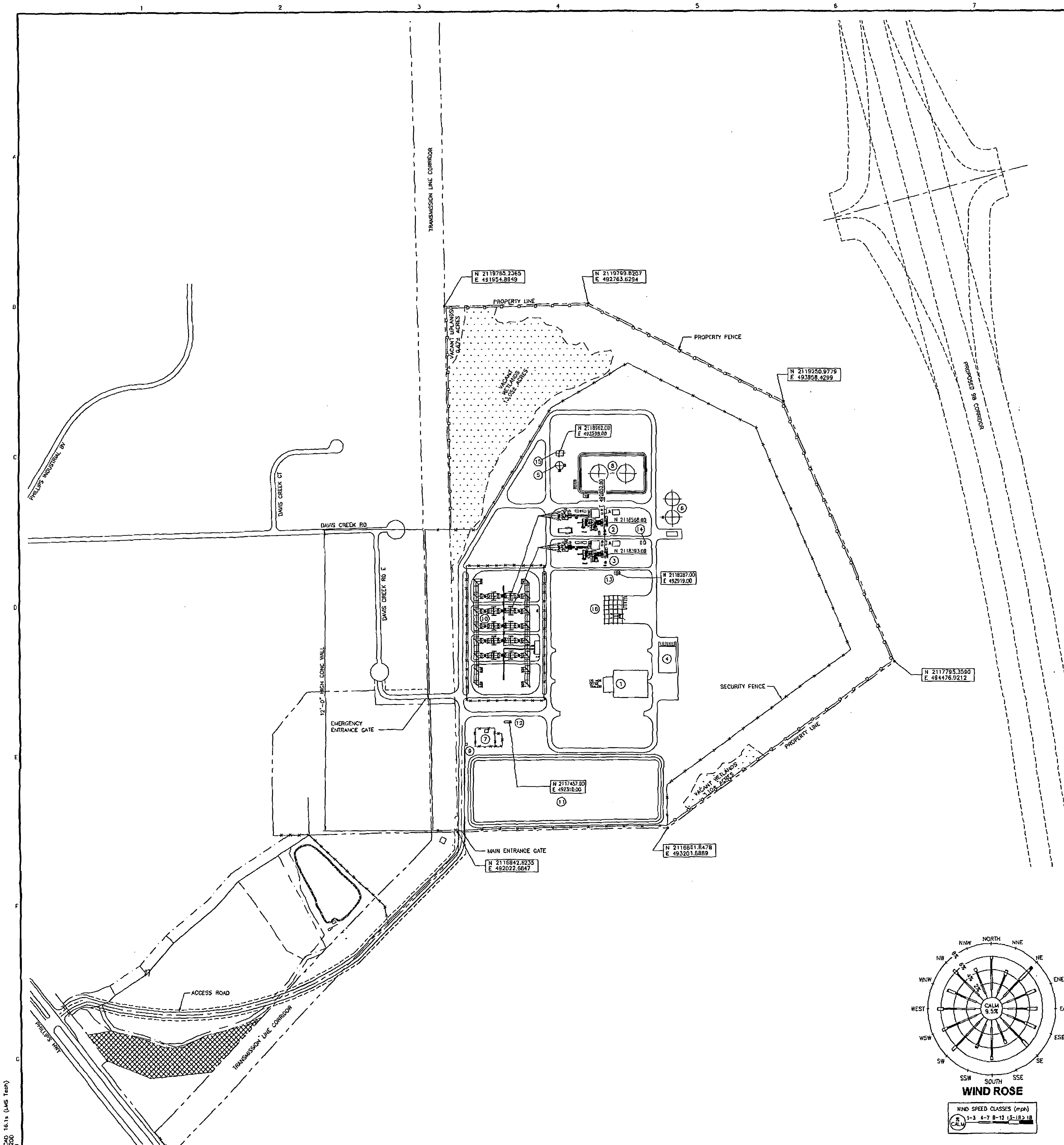
JEA
GREENLAND ENERGY CENTER

PLANT ARRANGEMENT - SIMPLE CYCLE
KEY PLAN

PROJECT / DRAWING NUMBER: 160167-CMA-M1001 | REV: A

CODE
AREA

CERTIFICATE OF AUTHORIZATION NO. 8132



FACILITIES LEGEND

ITEM NO	DESCRIPTION	LOCATION COORDINATES NORTH	EAST	REFERENCE LOCATION
1	(6) WIDE OFFICE TRAILER			
2	COMBUSTION TURBINE NO 1			CL STACK
3	COMBUSTION TURBINE NO 2			CL STACK
4	WAREHOUSE			
5	SERVICE / FIRE WATER TANK			
6	DEMIN WATER TANKS – 3 DAY STORAGE (1,600,000 GAL)			
7	GAS METERING STATION			
8	FUEL OIL TANKS W/CONTAINMENT – 5 DAY STORAGE (3,750,000 GAL)			
9	GUARD SHACK			
10	230 KVSUBSTATION			
11	RETENTION POND			
12	FUEL GAS HEATER			CL STACK
13	DIESEL GENERATOR			CL STACK
14	OIL WATER SEPARATOR			
15	FIRE PUMP BUILDING			
16	ADMIN/CONTROL/MAINTENANCE BUILDING			
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39				

GENERAL LEGEND

- FUTURE FACILITY
- 6' HIGH CHAIN LINK SECURITY FENCE
- 8' HIGH CHAIN LINK PROPERTY FENCE
- PROPERTY LINE

REFERENCE DRAWINGS

1.
2.
3.
4.
5.
6.
7.

NOTES

1. NOTE

NOT TO BE USED
FOR CONSTRUCTION

NO	DATE	REVISIONS AND RECORD OF ISSUE	DRN	DES	CHK	PDE	APP
A		INITIAL ISSUE	DS	DS	TD		

200' 100' 0 200' 400'
SCALE: 1"=200'

I HEREBY CERTIFY THAT THIS DOCUMENT WAS PREPARED BY ME OR UNDER MY DIRECT SUPERVISION AND THAT I AM A DULY REGISTERED PROFESSIONAL ENGINEER UNDER THE LAWS OF THE STATE OF FLORIDA
SIGNED ________
DATE ________ REG NO. ________

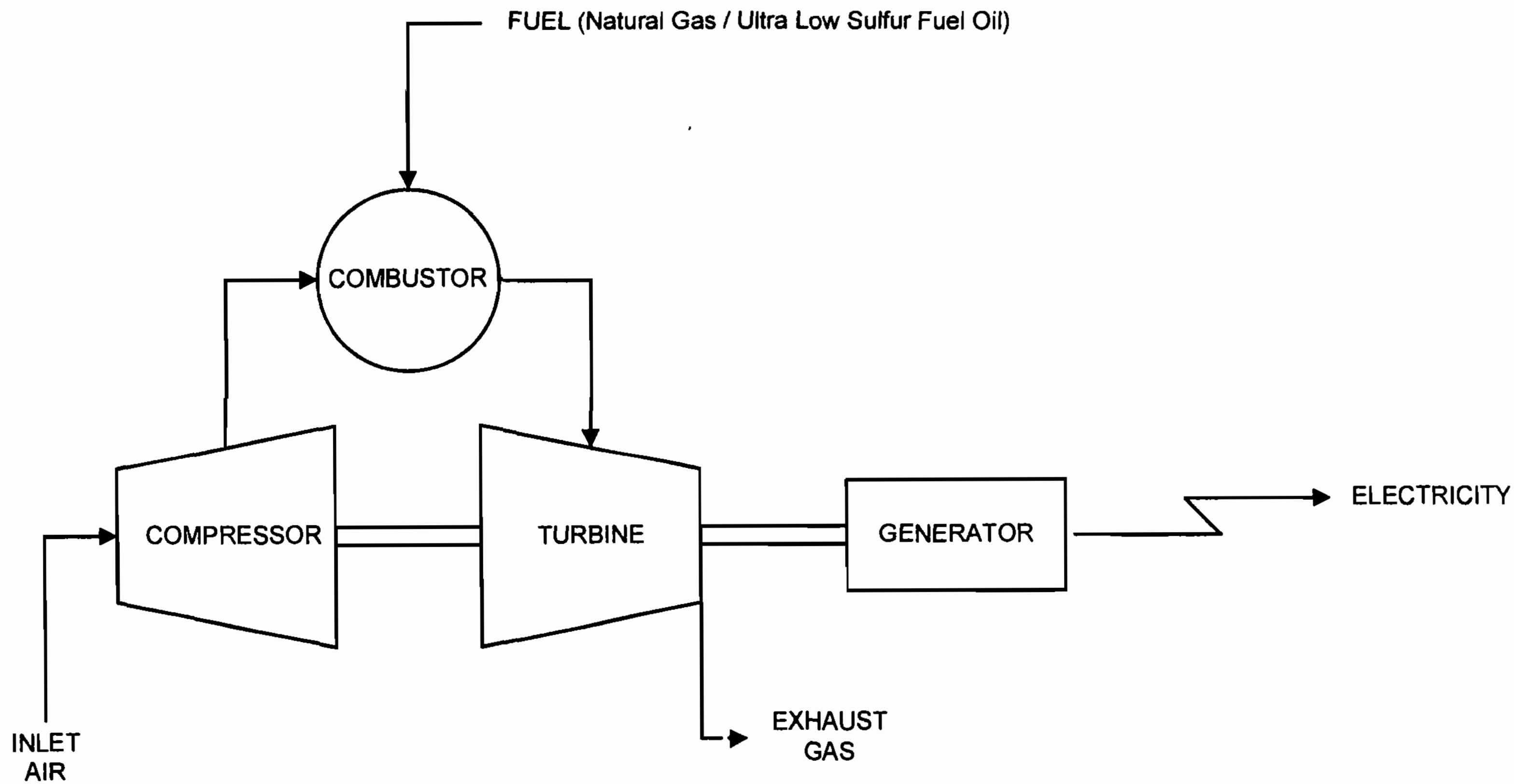
BLACK & VEATCH

ENGINEER TPO | DRAWN DAS
CHECKED | DATE

JEA
GREENLAND ENERGY CENTER
SITE ARRANGEMENT – SIMPLE CYCLE
UNITS 1 & 2

PROJECT / DRAWING NUMBER: 160167–CMA–S1000 | REV: A
CODE
AREA
CERTIFICATE OF AUTHORIZATION NO. 8132

Attachment 2
Process Flow Diagram



Greenland Energy Center
Simple Cycle Combustion Turbine
Process Flow Diagram

Attachment 3

Precautions to Prevent Emissions of Unconfined Particulate Matter

Attachment 3
Precautions to Prevent Emissions of Unconfined Particulate Matter

Reasonable precautions to control unconfined emissions of particulate matter as listed in Rule 62-296.320(4), FAC will be employed as appropriate. Additionally, watering will be used as needed to prevent emissions from unpaved areas.

Attachment 4
Rule Applicability Analysis

Attachment 4
Rule Applicability Analysis

Rule Applicability Analysis for the Entire Facility

- State: Rule 62-4.070 – Standards for Issuing or Denying Permits.
- State: Rule 62-210.300 – Permits Required.
- State: Rule 62-212.300 – General Preconstruction Review Requirements.
- State: Rule 62-212.400 – Prevention of Significant Deterioration.

Rule Applicability Analysis for the GE 7FA Simple Cycle Combustion Turbines Units 1 and 2

1. NOT APPLICABLE - Federal: 40 CFR Part 63 Subpart YYYY, *National Emission Standards for Stationary Combustion Turbines*. This standard is only applicable to emission units at a facility that is a major source of HAPs. Because the GEC is not and will not be a major source of HAPs after the project, 40 CFR 63 Subpart YYYY does not apply to the combustion turbine.
2. NOT APPLICABLE - Federal: 40 CFR Part 60 Subpart GG (Rule 62-204.800(8)(b).39) – *Standards of Performance for Stationary Gas Turbines*. Because the two SCCTs are each subject to NSPS Subpart KKKK, they are not subject to Subpart GG.

The following rules are applicable to the Project:

1. State: Rule 62-212.400 – *Prevention of Significant Deterioration* applies since the potential emissions of certain PSD applicable pollutants are greater than the PSD major source thresholds.
2. Federal: 40 CFR Part 60 Subpart KKKK – *Standards of Performance for Stationary Gas Turbines*
3. Federal: 40 CFR Part 60 Subpart A – *General Provisions.*
4. Federal: 40 CFR Part 72 – *Permits Regulation (Acid Rain)*
5. Federal: 40 CFR Part 75 – *Continuous Emissions Monitoring*
6. State: Rule 62-204.800(8)(d) – *General Provisions Adopted – 40 CFR 60 Subpart A – General Provisions adopted by reference, with exceptions.*
7. State: Rule 62-212.300 – *General Preconstruction Review Requirements.* Applies to all pollutants.
8. State: Rule 62-297.310 – *General Compliance Test Requirements.*

Rule Applicability Analysis for the two 1.875 Million Gallon ULSFO Storage Tanks

NOT APPLICABLE - Federal: 40 CFR Part 60 Subpart Kb, AS REVISED OCTOBER 15, 2003 – *Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984.* Because the vapor pressure of ULSFO is less than 3.5 kPa, the two ULSFO storage tanks are not subject to 40 CFR Part 60 Subpart Kb.

Rule Applicability Analysis for the Emergency Diesel Fire Pump and the Emergency Diesel Engine Generator

Rule Applicability Analysis for the Emergency Diesel Fire Pump

NOT APPLICABLE - Federal: 40 CFR Part 63 Subpart ZZZZ, *National Emission Standards for Reciprocating Internal Combustion Engines.* This standard is only applicable to emission units at a facility that is a major source of HAPs. Because the GEC will not be a major source of HAPs, 40 CFR 63 Subpart ZZZZ does not apply to the emergency diesel fire pump.

The following rules are applicable to the Emergency Diesel Fire Pump:

APPLICABLE - Federal: 40 CFR 60 Subpart IIII, *New Source Performance Standards for Stationary Compression Ignition Internal Combustion Engines*

The emergency diesel fire pump will be subject to the manufacturer's certification requirements of compliance under the NSPS for RICE (40 CFR Part 60, Subpart IIII). The rule provides various emission standards based on the engine's classification, use, manufacture date, and engine size. The fire pump engines will need to meet the emission requirements listed in Table 4 of the regulation.

State: Rule 62-212.400 – *Prevention of Significant Deterioration (PSD)*

Rule Applicability Analysis for the Emergency Diesel Engine Generator

NOT APPLICABLE - Federal: 40 CFR Part 63 Subpart ZZZZ, *National Emission Standards for Reciprocating Internal Combustion Engines.* This standard is only applicable to emission units at a facility that is a major source of HAPs. Because the GEC will not be a major source of HAPs, 40 CFR 63 Subpart ZZZZ does not apply to the safe shutdown diesel generator.

APPLICABLE - Federal: 40 CFR 60 Subpart IIII, *New Source Performance Standards for Stationary Compression Ignition Internal Combustion Engines*

The emergency diesel engine generator will be subject to the manufacturer's certification requirements of compliance under the NSPS for RICE (40 CFR Part 60, Subpart IIII). The rule provides various emission standards based on the engine's classification, use, manufacture date, and engine size.

State: Rule 62-212.400 – *Prevention of Significant Deterioration (PSD)*

Attachment 5
List of Exempt Units

Attachment 5
List of Exempt Emission Units

In accordance with Rule 62-210.300(3), F.A.C., the following emission units are exempt.

1. Emergency Diesel Engine Generator

   The emergency diesel engine generator along with the emergency diesel fire pump will combust no more that 32,000 gallons per year of diesel. This emission unit is categorically exempt in accordance with 62-210.300(3)(a) 35.

2. Emergency Diesel Fire Pump

   The emergency diesel fire pump along with the emergency diesel generator will combust no more that 32,000 gallons per year of diesel. This emission unit is categorically exempt in accordance with 62-210.300(3)(a) 36.

3. Two 1.875 Million Gallon ULSFO Storage Tanks

   Each of the ULSFO storage tanks are generically exempt from the permitting requirements of Chapter 62-212, F.A.C. because it satisfies the applicable criteria of paragraph 62-210.300(3)(b)1., F.A.C.

4. 5.84 MBtu/hour natural gas fired fuel gas heater

   The fuel gas heater is categorically exempt in accordance with 62-210.300(3)(a) 33.

5. 2,500 gallon ULSFO Day Tank for the Emergency Engine Generator

   This day tank is generically exempt from the permitting requirements of Chapter 62-212, F.A.C. because it satisfies the applicable criteria of paragraph 62-210.300(3)(b)1., F.A.C.

6. 500 gallon ULSFO Day Tank for the Emergency Diesel Fire Pump

   This day tank is generically exempt from the permitting requirements of Chapter 62-212, F.A.C. because it satisfies the applicable criteria of paragraph 62-210.300(3)(b)1., F.A.C.

Attachment 6
Fuel Analysis or Specification

Attachment 6
Fuel Analysis or Specification

Fuel is specified as pipeline natural gas or ultra low sulfur No. 2 fuel oil containing no more than 0.0015 percent sulfur.

Attachment 7
Operation and Maintenance Plan

Attachment 7
Operation and Maintenance Plan

The emission units will be operated and maintained in accordance with manufacturer's recommendations, operations and maintenance experience, and technical guidance taking into account protection of equipment, safety of personnel and other factors as deemed necessary to maintain compliance with the permitted limits.

Attachment 8
Description of Stack Sampling Facilities

Attachment 8
Description of Stack Sampling Facilities

Units 1 and 2 will be equipped with stack sampling facilities appropriate for performing required stack testing. A detailed description of stack sampling facilities is not available at this time. When available, if requested by the Department, the stack sampling facilities description will be supplied to the Department.

Attachment 9
Acid Rain/CAIR/CAMR Program Forms

Attachment 9
Acid Rain/CAIR/CAMR Program Forms

In accordance with 62-213.420 F.A.C., since Units 1 and 2 are not yet covered by a Title V permit prior to May 1, 2008, a certified CAIR Part form and a certified Hg Budget Part form will be submitted to the Department prior to the unit commencing operation. JEA understands that the forms will be incorporated into the facility's Title V permit.

In accordance with 62-214.320, JEA will submit a complete Acid Rain Part application governing Units 1 and 2 operations to the Department at least 24 months before the date on which the units commence operation. The Acid Rain Part application will be submitted under a separate cover.

Appendix B
Combustion Turbine Performance Data and Ancillary Equipment Specification Sheets

Simple Cycle Combustion Turbine Performance Data

12-Feb-08
JEA
Simple Cycle Emissions
Rev1, Revision 1

Case Number	1	2	3	4	5	6	7	8	9	10	11	12
CTG Model	GEPG7241	GEPG7241	GEPG7241	GEPG7241	GEPG7241	GEPG7241	GEPG7241	GEPG7241	GEPG7241	GEPG7241	GEPG7241	GEPG7241
CTG Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Load	100%	75%	50%	100%	75%	50%	100%	75%	50%	100%	75%	50%
CTG Inlet Air Cooling	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off
CTG Steam/Water Injection	No	No	No	No	No	No	No	No	No	No	No	No
Ambient Temperature, F	7	7	7	59	59	59	68.8	68.8	68.8	105	105	105
Fuel Sulfur Content (grains/100 standard cubic feet)	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Ambient Conditions												
Ambient Temperature, F	7.0	7.0	7.0	59.0	59.0	59.0	68.8	68.8	68.8	105.0	105.0	105.0
Ambient Relative Humidity, %	74.0	74.0	74.0	60.0	60.0	60.0	73.0	73.0	73.0	35.0	35.0	35.0
Atmospheric Pressure, psia	14.690	14.690	14.690	14.690	14.690	14.690	14.690	14.690	14.690	14.690	14.690	14.690
Combustion Turbine Performance												
CTG Performance Reference	GE	GE	GE	GE	GE	GE	GE	GE	GE	GE	GE	GE
CTG Inlet Air Conditioning Effectiveness, %	0	0	0	0	0	0	0	0	0	0	0	0
CTG Compressor Inlet Dry Bulb Temperature, F	7.0	7.0	7.0	59.0	59.0	59.0	68.8	68.8	68.8	105.0	105.0	105.0
CTG Compr Inlet Relative Humidity, %	74.2	74.2	74.2	60.1	60.1	60.1	73.1	73.1	73.1	35.1	35.1	35.1
Inlet Loss, in H2O	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
Exhaust Loss, in. H2O	6.5	4.1	2.7	5.5	3.6	2.5	5.3	3.5	2.4	4.4	3.1	2.2
CTG Load Level (percent of Base Load)	100%	75%	50%	100%	75%	50%	100%	75%	50%	100%	75%	50%
Gross CTG Output, kW	195,900	146,900	97,900	176,200	132,100	88,100	171,000	128,300	85,500	147,200	110,400	73,600
Gross CTG Heat Rate, Btu/kWh (LHV)	9,095	9,780	11,660	9,235	10,030	12,070	9,310	10,150	12,190	9,710	10,820	12,890
Gross CTG Heat Rate, Btu/kWh (HHV)	10,092	10,853	12,939	10,248	11,130	13,394	10,331	11,263	13,527	10,775	12,007	14,304
CTG Heat Input, MBtu/h (LHV)	1,781.7	1,436.7	1,141.5	1,627.2	1,325.0	1,063.4	1,592.0	1,302.3	1,042.3	1,429.3	1,194.5	948.7
CTG Heat Input, MBtu/h (HHV)	1,977.1	1,594.2	1,266.7	1,805.7	1,470.3	1,180.0	1,766.6	1,445.1	1,156.6	1,586.1	1,325.5	1,052.7
CTG Water/Steam Injection Flow, lb/h	0	0	0	0	0	0	0	0	0	0	0	0
Injection Fluid/Fuel Ratio	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CTG Exhaust Flow, lb/h	3,959,000	3,095,000	2,521,000	3,608,000	2,902,000	2,399,000	3,526,000	2,858,000	2,372,000	3,203,000	2,692,000	2,262,000
CTG Exhaust Temperature, F	1,060	1,118	1,169	1,111	1,154	1,200	1,121	1,162	1,200	1,158	1,195	1,200
Combustion Turbine Fuel												
Total CTG Fuel Flow, lb/h	85,620	69,040	54,860	78,200	63,670	51,100	76,510	62,580	50,090	68,690	57,400	45,590
CTG Fuel Temperature, F	80	80	80	80	80	80	80	80	80	80	80	80
CTG Fuel LHV, Btu/lb	20,809	20,809	20,809	20,809	20,809	20,809	20,809	20,809	20,809	20,809	20,809	20,809
CTG Fuel HHV, Btu/lb	23,091	23,091	23,091	23,091	23,091	23,091	23,091	23,091	23,091	23,091	23,091	23,091
HHV/LHV Ratio	1.1097	1.1097	1 1097	1.1097	1.1097	1.1097	1.1097	1.1097	1.1097	1.1097	1.1097	1.1097
CTG Fuel Composition (Ultimate Analysis by Weight)												
Ar	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
C	73.78%	73.78%	73.78%	73.78%	73.78%	73.78%	73.78%	73.78%	73.78%	73.78%	73.78%	73.78%
H2	24.02%	24.02%	24.02%	24.02%	24.02%	24.02%	24.02%	24.02%	24.02%	24.02%	24.02%	24.02%
N2	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%
O2	1.60%	1.60%	1.60%	1.60%	1.60%	1.60%	1.60%	1.60%	1.60%	1.60%	1.60%	1.60%
S	0.00658%	0.00658%	0.00658%	0.00658%	0.00658%	0.00658%	0.00658%	0.00658%	0.00658%	0.00658%	0.00658%	0.00658%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Fuel Sulfur Content (grains/100 standard cubic feet)	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00

Owner JEA
Plant JEA Greenland Energy Center
Project No. 160167.005
Title Rev1, Revision 1

Computed By VV
Date 02/12/2008

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Case Number	1	2	3	4	5	6	7	8	9	10	11	12
CTG Model	GEPG7241	GEPG7241	GEPG7241	GEPG7241	GEPG7241	GEPG7241	GEPG7241	GEPG7241	GEPG7241	GEPG7241	GEPG7241	GEPG7241
CTG Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Load	100%	75%	50%	100%	75%	50%	100%	75%	50%	100%	75%	50%
CTG Inlet Air Cooling	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off
CTG Steam/Water Injection	No	No	No	No	No	No	No	No	No	No	No	No
Ambient Temperature, F	7	7	7	59	59	59	68.8	68.8	68.8	105	105	105
Fuel Sulfur Content (grains/100 standard cubic feet)	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Stack Emissions												
Stack Exhaust Analysis - Volume Basis - Wet												
Ar	0.94%	0.94%	0.94%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	0.92%	0.92%	0.92%
CO2	3.79%	3.90%	3.81%	3.78%	3.83%	3.72%	3.78%	3.81%	3.68%	3.72%	3.70%	3.50%
H2O	7.49%	7.72%	7.53%	8.32%	8.41%	8.19%	9.01%	9.07%	8.82%	9.77%	9.73%	9.35%
N2	75.03%	74.94%	75.01%	74.38%	74.35%	74.43%	73.84%	73.81%	73.91%	73.20%	73.21%	73.36%
O2	12.75%	12.50%	12.70%	12.59%	12.49%	12.73%	12.45%	12.38%	12 67%	12.39%	12.44%	12.87%
SO2 (after SO2 oxidation)	0.000100%	0.000100%	0.000100%	0.000100%	0.000100%	0.000100%	0.000100%	0.000100%	0.000100%	0.000100%	0.000100%	0.000090%
SO3 (after SO2 oxidation)	0.000030%	0.000030%	0.000030%	0.000030%	0.000030%	0.000020%	0.000030%	0.000030%	0.000020%	0.000020%	0.000020%	0.000020%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Stack Exit Temperature, F	1060	1118	1169	1111	1154	1200	1121	1162	1200	1158	1195	1200
Stack Diameter, ft (estimated)	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Stack Flow, lb/h	3,958,996	3,094,997	2,520,997	3,607,996	2,901,997	2,398,998	3,525,996	2,857,997	2,371,998	3,202,997	2,691,997	2,261,998
Stack Flow, scfm	878,898	687,090	559,662	803,381	646,179	533,778	786,886	638,287	529,351	717,472	603,008	505,934
Stack Flow, acfm	2,570,051	2,087,062	1,754,196	2,428,785	2,007,217	1,706,089	2,395,329	1,992,026	1,691,236	2,233,559	1,920,293	1,616,953
Stack Exit Velocity, ft/s	136.0	111.0	93.0	129.0	106.0	91.0	127.0	106.0	90.0	118.0	102.0	86.0
Stack NOx Emissions												
NOx, ppmvd (dry, 15% O2)	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
NOx, ppmvd (dry)	10.8	11.2	10.9	10.9	11.1	10.7	11.0	11.1	10.7	10.9	10.8	10.2
NOx, ppmvw (wet)	10.0	10.3	10.1	10.0	10.1	9.8	10.0	10.1	9.7	9.8	9.8	9.3
NOx, lb/h as NO2	64.0	51.6	41.0	58.5	47.6	38.2	57.2	47.0	37.4	51.4	43.0	34.1
NOx, lb/MBtu (LHV) as NO2	0.0359	0.0359	0.0359	0.0359	0.0359	0.0359	0.0359	0.0361	0.0359	0.0359	0.0360	0.0359
NOx, lb/MBtu (HHV) as NO2	0.0324	0.0324	0.0324	0.0324	0.0324	0.0324	0.0324	0.0325	0.0324	0.0324	0.0324	0.0324
Stack CO Emissions												
CO, ppmvd (dry, 15% O2)	4.1	7.2	7.4	4.1	7.3	7.6	4.1	7.3	7.6	4.1	7.5	7.9
CO, ppmvd (dry)	4.9	9.0	9.0	5.0	9.0	9.0	5.0	9.0	9.0	5.0	9.0	9.0
CO, ppmvw (wet)	4.6	8.3	8.3	4.6	8.2	8.3	4.5	8.2	8.2	4.5	8.1	8.2
CO, lb/h	17.8	25.3	21.0	16.2	24.0	20.0	15.9	23.1	19.2	14.2	22.0	18.3
CO, lb/MBtu (LHV)	0.0100	0.0176	0.0184	0.0100	0.0181	0.0188	0.0100	0.0178	0.0185	0.0100	0.0184	0.0193
CO, lb/MBtu (HHV)	0.0090	0.0159	0.0166	0.0090	0.0163	0.0169	0.0090	0.0160	0.0166	0.0090	0.0166	0.0174
Stack SO2 Emissions												
SO2, ppmvd (dry, 15% O2)	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91
SO2, ppmvd (dry)	1.09	1.13	1.10	1.10	1.12	1.08	1.11	1.12	1.08	1.10	1.10	1.03
SO2, ppmvw (wet)	1.01	1.04	1.02	1.01	1.02	0.99	1.01	1.02	0.98	0.99	0.99	0.94
SO2, lb/h	9.01	7.27	5.77	8.23	6.70	5.38	8.05	6.59	5.27	7.23	6.04	4.80
SO2, lb/MBtu (LHV)	0.0051	0.0051	0.0051	0.0051	0.0051	0.0051	0.0051	0.0051	0.0051	0.0051	0.0051	0.0051
SO2, lb/MBtu (HHV)	0.0046	0.0046	0.0046	0.0046	0.0046	0.0046	0.0046	0.0046	0.0046	0.0046	0.0046	0.0046

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Case Number	1	2	3	4	5	6	7	8	9	10	11	12
CTG Model	GEPG7241	GEPG7241	GEPG7241	GEPG7241	GEPG7241	GEPG7241	GEPG7241	GEPG7241	GEPG7241	GEPG7241	GEPG7241	GEPG7241
CTG Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
CTG Load	100%	75%	50%	100%	75%	50%	100%	75%	50%	100%	75%	50%
CTG Inlet Air Cooling	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off
CTG Steam/Water Injection	No	No	No	No	No	No	No	No	No	No	No	No
Ambient Temperature, F	7	7	7	59	59	59	68.8	68.8	68.8	105	105	105
Fuel Sulfur Content (grains/100 standard cubic feet)	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Stack Emissions - continued												
Stack UHC Emissions												
UHC, ppmvd (dry, 15% O2)	6.3	6.1	6.3	6.3	6.2	6.4	6.3	6.3	6.5	6.4	6.4	6.8
UHC, ppmvd	7.6	7.6	7.6	7.6	7.6	7.6	7.7	7.7	7.7	7.8	7.8	7.7
UHC, ppmvw	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
UHC, lb/h as CH4	15.6	12.2	10.0	14.3	11.5	9.5	14.0	11.3	9.4	12.7	11.0	9.0
UHC, lb/MBtu (LHV)	0.0088	0.0085	0.0088	0.0088	0.0087	0.0089	0.0088	0.0087	0.0090	0.0089	0.0092	0.0095
UHC, lb/MBtu (HHV)	0.0079	0.0077	0.0079	0.0079	0.0078	0.0080	0.0079	0.0078	0.0081	0.0080	0.0083	0.0085
Stack VOC Emissions												
VOC, ppmvd (dry, 15% O2)	1.3	1.2	1.3	1.3	1.2	1.3	1.3	1.3	1.3	1.3	1.3	1.4
VOC, ppmvd (dry)	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.6	1.6	1.5
VOC, ppmvw (wet)	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
VOC, lb/h as CH4	3.1	2.4	2.0	2.9	2.3	1.9	2.8	2.3	1.9	2.5	2.2	1.8
VOC, lb/MBtu (LHV)	0.0018	0.0017	0.0018	0.0018	0.0017	0.0018	0.0018	0.0017	0.0018	0.0018	0.0018	0.0019
VOC, lb/MBtu (HHV)	0.0016	0.0015	0.0016	0.0016	0.0016	0.0016	0.0016	0.0016	0.0016	0.0016	0.0017	0.0017
PM10 without the Effects of SO2 oxidation												
PM10 Emissions - Front Half Catch Only												
PM10, lb/h	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
PM10, lb/MBtu (LHV)	0.0051	0.0063	0.0079	0.0055	0.0068	0.0085	0.0057	0.0069	0.0086	0.0063	0.0075	0.0095
PM10, lb/MBtu (HHV)	0.0046	0.0056	0.0071	0.0050	0.0061	0.0076	0.0051	0.0062	0.0078	0.0057	0.0068	0.0085
PM10 Emissions - Front and Back Half Catch												
PM10, lb/h	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0
PM10, lb/MBtu (LHV)	0.0101	0.0125	0.0158	0.0111	0.0136	0.0169	0.0113	0.0138	0.0173	0.0126	0.0151	0.0190
PM10, lb/MBtu (HHV)	0.0091	0.0113	0.0142	0.0100	0.0122	0.0153	0.0102	0.0125	0.0156	0.0113	0.0136	0.0171
Total Effects of SO2 Oxidation												
Total SO2 to SO3 conversion rate, %vol	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%
Total Amount of SO2 converted to SO3, lb/h	2.25	1.82	1.44	2.06	1.67	1.34	2.01	1.65	1.32	1.81	1.51	1.20
Maximum Stack H2SO4 (assuming 100% conversion from SO3 to H2SO4), lb/h	3.45	2.78	2.21	3.15	2.56	2.06	3.08	2.52	2.02	2.77	2.31	1.84

Notes:

1. The emissions estimates shown in the table are for Simple Cycle GE-7FA Gas Turbines
2. The dry air composition used is 0.98% Ar, 78.03% N2 and 20.99%O2
3. ISO conditions are defined as 59 F, 14.696 psia and 60% RH, Norm conditions are defined as 0 C, 1.103 bar
4. All ppm values are based on CH4 calibration gas
5. The CTG performance is provided by General Electric dated 12/10/2007
6. Emission values at part loads and base loads are based on the JEA Kennedy guarantee provided by GE and TCEC Unit 1 permit guarantee respectively
7. The front half catch of particulate emissions is assumed to be half the amount of the front and back half catch. estimate and B&V's estimate was used in the summary table, i.e the B&V estimates were adjusted, were applicable.

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Case Number	13	14	15	16	17	18	19	20	21	22	23	24
CTG Model	GEPG7241	GEPG7241	GEPG7241	GEPG7241	GEPG7241	GEPG7241	GEPG7241	GEPG7241	GEPG7241	GEPG7241	GEPG7241	GEPG7241
CTG Fuel Type	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate
CTG Load	100%	75%	50%	100%	75%	50%	100%	75%	50%	100%	75%	50%
CTG Inlet Air Cooling	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off
CTG Steam/Water Injection	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water
Ambient Temperature, F	7	7	7	59	59	59	68.8	68.8	68.8	105	105	105
Fuel Sulfur Content (grains/100 standard cubic feet)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Ambient Conditions												
Ambient Temperature, F	7.0	7.0	7.0	59.0	59.0	59.0	68.8	68.8	68.8	105.0	105.0	105.0
Ambient Relative Humidity, %	74.0	74.0	74.0	60.0	60.0	60.0	73.0	73.0	73.0	35.0	35.0	35.0
Atmospheric Pressure, psia	14.690	14.690	14.690	14.690	14.690	14.690	14.690	14.690	14.690	14.690	14.690	14.690
Combustion Turbine Performance												
CTG Performance Reference	GE	GE	GE	GE	GE	GE	GE	GE	GE	GE	GE	GE
CTG Inlet Air Conditioning Effectiveness, %	0	0	0	0	0	0	0	0	0	0	0	0
CTG Compressor Inlet Dry Bulb Temperature, F	7.0	7.0	7.0	59.0	59.0	59.0	68.8	68.8	68.8	105.0	105.0	105.0
CTG Compr Inlet Relative Humidity, %	74.2	74.2	74.2	60.1	60.1	60.1	73.1	73.1	73.1	35.1	35.1	35.1
Inlet Loss, in. H2O	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
Exhaust Loss, in. H2O	7.1	4.2	2.8	6.0	3.8	2.6	5.7	3.7	2.6	4.7	3.3	2.4
CTG Load Level (percent of Base Load)	100%	75%	50%	100%	75%	50%	100%	75%	50%	100%	75%	50%
Gross CTG Output, kW	206,000	154,500	103,000	189,600	142,200	94,800	184,500	138,300	92,200	161,000	120,700	80,500
Gross CTG Heat Rate, Btu/kWh (LHV)	9,815	10,470	12,300	9,875	10,640	12,590	9,905	10,710	12,660	10,210	11,230	13,230
Gross CTG Heat Rate, Btu/kWh (HHV)	10,453	11,151	13,100	10,517	11,332	13,409	10,549	11,406	13,483	10,874	11,960	14,090
CTG Heat Input, MBtu/h (LHV)	2,021.9	1,617.6	1,266.9	1,872.3	1,513.0	1,193.5	1,827.5	1,481.2	1,167.3	1,643.8	1,355.5	1,065.0
CTG Heat Input, MBtu/h (HHV)	2,153.4	1,722.8	1,349.3	1,994.1	1,611.4	1,271.1	1,946.3	1,577.5	1,243.2	1,750.7	1,443.6	1,134.3
CTG Water/Steam Injection Flow, lb/h	147,980	110,260	77,520	136,380	100,690	71,360	128,570	94,890	66,560	110,620	82,480	56,350
Injection Fluid/Fuel Ratio	1.3	1.3	1.1	1.3	1.2	1.1	1.3	1.2	1.0	1.2	1.1	1.0
CTG Exhaust Flow, lb/h	4,132,000	3,146,000	2,550,000	3,768,000	2,991,000	2,448,000	3,677,000	2,947,000	2,426,000	3,328,000	2,764,000	2,326,000
CTG Exhaust Temperature, F	1,040	1,120	1,170	1,094	1,152	1,200	1,105	1,160	1,200	1,147	1,191	1,200
Combustion Turbine Fuel												
Total CTG Fuel Flow, lb/h	110,490	88,390	69,230	102,310	82,680	65,220	99,860	80,940	63,780	89,830	74,070	58,200
CTG Fuel Temperature, F	80	80	80	80	80	80	80	80	80	80	80	80
CTG Fuel LHV, Btu/lb	18,300	18,300	18,300	18,300	18,300	18,300	18,300	18,300	18,300	18,300	18,300	18,300
CTG Fuel HHV, Btu/lb	19,490	19,490	19,490	19,490	19,490	19,490	19,490	19,490	19,490	19,490	19,490	19,490
HHV/LHV Ratio	1.0650	1.0650	1.0650	1.0650	1.0650	1.0650	1.0650	1.0650	1.0650	1.0650	1.0650	1.0650
CTG Fuel Composition (Ultimate Analysis by Weight)												
Ar	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
C	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%
H2	14.80%	14.80%	14.80%	14.80%	14.80%	14.80%	14.80%	14.80%	14.80%	14.80%	14.80%	14.80%
N2	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%
O2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
S	0.00150%	0.00150%	0.00150%	0.00150%	0.00150%	0.00150%	0.00150%	0.00150%	0.00150%	0.00150%	0.00150%	0.00150%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Fuel Sulfur Content (grains/100 standard cubic feet)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

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Case Number	13	14	15	16	17	18	19	20	21	22	23	24
CTG Model	GEPG7241	GEPG7241	GEPG7241	GEPG7241	GEPG7241	GEPG7241	GEPG7241	GEPG7241	GEPG7241	GEPG7241	GEPG7241	GEPG7241
CTG Fuel Type	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate
CTG Load	100%	75%	50%	100%	75%	50%	100%	75%	50%	100%	75%	50%
CTG Inlet Air Cooling	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off
CTG Steam/Water Injection	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water
Ambient Temperature, F	7	7	7	59	59	59	68.8	68.8	68 8	105	105	105
Fuel Sulfur Content (grains/100 standard cubic feet)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Stack Emissions												
Stack Exhaust Analysis - Volume Basis - Wet												
Ar	0.90%	0.90%	0.90%	0.89%	0.89%	0.90%	0.88%	0.89%	0.90%	0.88%	0.88%	0.89%
CO2	5.35%	5.63%	5.45%	5.42%	5.52%	5.34%	5.41%	5.48%	5.26%	5.37%	5.34%	5.00%
H2O	11.32%	11.48%	10.59%	12.22%	11.94%	11.07%	12.68%	12.33%	11 39%	13 19%	12.66%	11.47%
N2	71.37%	71.35%	71.98%	70.69%	70.95%	71.56%	70.33%	70.63%	71.27%	69.91%	70.32%	71.11%
O2	11.07%	10.65%	11.08%	10.79%	10.69%	11.14%	10.70%	10.67%	11.18%	10.66%	10.81%	11.53%
SO2 (after SO2 oxidation)	0.000030%	0.000030%	0.000030%	0 000030%	0.000030%	0.000030%	0.000030%	0.000030%	0.000030%	0.000030%	0.000030%	0.000030%
SO3 (after SO2 oxidation)	0.000010%	0.000010%	0.000010%	0.000010%	0.000010%	0.000010%	0.000010%	0.000010%	0 000010%	0.000010%	0.000010%	0.000010%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Stack Exit Temperature, F	1040	1120	1170	1094	1152	1200	1105	1160	1200	1147	1191	1200
Stack Diameter, ft (estimated)	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Stack Flow, lb/h	4,131,999	3,145,999	2,549,999	3,767,999	2,990,999	2,447,999	3,676,999	2,946,999	2,425,999	3,327,999	2,763,999	2,325,999
Stack Flow, scfm	923,502	703,131	568,225	845,288	669,984	546,720	826,099	661,110	542,615	749,355	620,979	521,024
Stack Flow, acfm	2,666,517	2,137,707	1,782,450	2,527,700	2,078,247	1,746,648	2,488,103	2,060,935	1,733,781	2,317,397	1,973,496	1,664,253
Stack Exit Velocity, ft/s	141.0	113.0	95.0	134.0	110.0	93.0	132.0	109.0	92.0	123.0	105.0	88.0
Stack NOx Emissions												
NOx, ppmvd (dry, 15% O2)	42 0	42 0	42.0	42 0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0
NOx, ppmvd (dry)	59.7	62.8	60.3	61 0	62.0	59.4	61.2	61.8	58.7	61.1	60.4	55.8
NOx, ppmvw (wet)	52.9	55.6	53.9	53 6	54.6	52.8	53.5	54.2	52 0	53.0	52.5	49.4
NOx, lb/h as NO2	355.7	284.5	222 9	329 4	266.2	210.0	321.5	260.6	205.3	289.2	238.4	187.4
NOx, lb/MBtu (LHV) as NO2	0.1759	0.1759	0.1759	0.1759	0 1759	0.1759	0.1759	0.1759	0.1759	0.1759	0.1759	0.1759
NOx, lb/MBtu (HHV) as NO2	0.1652	0 1652	0.1652	0.1652	0.1652	0.1652	0.1652	0.1652	0.1652	0.1652	0.1652	0.1652
Stack CO Emissions												
CO, ppmvd (dry, 15% O2)	8.0	13.4	13.9	8.0	13.5	14.2	8.0	13.6	14.3	8.0	13.9	15.0
CO, ppmvd (dry)	11.4	20.0	20.0	11.6	20.0	20.0	11.7	20.0	20.0	11.6	20.0	20.0
CO, ppmvw (wet)	10.1	17.7	17.9	10.2	17.6	17.8	10 2	17.5	17 7	10.1	17.5	17.7
CO, lb/h	41.2	55.1	45.0	38.2	52.3	43.1	37.3	52.0	43.0	33.5	48 1	41.0
CO, lb/MBtu (LHV)	0.0204	0.0341	0.0355	0.0204	0.0345	0.0361	0.0204	0.0351	0.0368	0.0204	0.0355	0.0385
CO, lb/MBtu (HHV)	0.0192	0.0320	0.0334	0.0192	0.0324	0.0339	0.0192	0.0330	0.0346	0.0192	0.0333	0.0361
Stack SO2 Emissions												
SO2, ppmvd (dry, 15% O2)	0.22	0.22	0.22	0.22	0 22	0.22	0.22	0.22	0.22	0.22	0.22	0.22
SO2, ppmvd (dry)	0.32	0.34	0.32	0.33	0.33	0.32	0.33	0.33	0.31	0.33	0.32	0.30
SO2, ppmvw (wet)	0.28	0.30	0.29	0.29	0.29	0.28	0.29	0.29	0.28	0.28	0.28	0.26
SO2, lb/h	2.65	2.12	1.66	2.45	1.98	1.56	2.39	1.94	1.53	2.15	1.78	1.40
SO2, lb/MBtu (LHV)	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013
SO2, lb/MBtu (HHV)	0 0012	0.0012	0.0012	0.0012	0.0012	0.0012	0.0012	0.0012	0.0012	0.0012	0.0012	0.0012

12-Feb-08
JEA
Simple Cycle Emissions
Rev1, Revision 1

Case Number	13	14	15	16	17	18	19	20	21	22	23	24
CTG Model	GEPG7241	GEPG7241	GEPG7241	GEPG7241	GEPG7241	GEPG7241	GEPG7241	GEPG7241	GEPG7241	GEPG7241	GEPG7241	GEPG7241
CTG Fuel Type	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate
CTG Load	100%	75%	50%	100%	75%	50%	100%	75%	50%	100%	75%	50%
CTG Inlet Air Cooling	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off
CTG Steam/Water Injection	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water
Ambient Temperature, F	7	7	7	59	59	59	68.8	68.8	68.8	105	105	105
Fuel Sulfur Content (grains/100 standard cubic feet)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Stack Emissions - continued												
Stack UHC Emissions												
UHC, ppmvd (dry, 15% O2)	5.6	5.3	5.5	5.5	5.4	5.6	5.5	5.4	5.7	5.5	5.6	5.9
UHC, ppmvd	7.9	7.9	7.8	8.0	7.9	7.9	8.0	8.0	7.9	8.1	8.0	7.9
UHC, ppmvw	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
UHC, lb/h as CH4	16.4	12.5	10.1	15.0	12.0	10.0	14.7	12.0	10.0	13.3	11.0	9.3
UHC, lb/MBtu (LHV)	0.0081	0.0077	0.0080	0.0080	0.0079	0.0084	0.0080	0.0081	0.0086	0.0081	0.0081	0.0087
UHC, lb/MBtu (HHV)	0.0076	0.0072	0.0075	0.0075	0.0074	0.0079	0.0075	0.0076	0.0080	0.0076	0.0076	0.0082
Stack VOC Emissions												
VOC, ppmvd (dry, 15% O2)	1.6	2.6	2.7	1.6	2.7	2.8	1.6	2.7	2.8	1.6	2.8	3.0
VOC, ppmvd (dry)	2.3	4.0	3.9	2.3	4.0	3.9	2.3	4.0	3.9	2.3	4.0	4.0
VOC, ppmvw (wet)	2.0	3.5	3.5	2.0	3.5	3.5	2.0	3.5	3.5	2.0	3.5	3.5
VOC, lb/h as CH4	4.7	6.2	5.0	4.3	6.0	5.0	4.2	6.0	5.0	3.8	5.5	4.6
VOC, lb/MBtu (LHV)	0.0023	0.0039	0.0040	0.0023	0.0040	0.0042	0.0023	0.0041	0.0043	0.0023	0.0041	0.0043
VOC, lb/MBtu (HHV)	0.0022	0.0036	0.0037	0.0022	0.0037	0.0039	0.0022	0.0038	0.0040	0.0022	0.0038	0.0041
PM10 without the Effects of SO2 oxidation												
PM10 Emissions - Front Half Catch Only												
PM10, lb/h	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0
PM10, lb/MBtu (LHV)	0.0084	0.0105	0.0134	0.0091	0.0112	0.0142	0.0093	0.0115	0.0146	0.0103	0.0125	0.0160
PM10, lb/MBtu (HHV)	0.0079	0.0099	0.0126	0.0085	0.0105	0.0134	0.0087	0.0108	0.0137	0.0097	0.0118	0.0150
PM10 Emissions - Front and Back Half Catch												
PM10, lb/h	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0
PM10, lb/MBtu (LHV)	0.0168	0.0210	0.0268	0.0182	0.0225	0.0285	0.0186	0.0230	0.0291	0.0207	0.0251	0.0319
PM10, lb/MBtu (HHV)	0.0158	0.0197	0.0252	0.0171	0.0211	0.0267	0.0175	0.0216	0.0273	0.0194	0.0236	0.0300
Total Effects of SO2 Oxidation												
Total SO2 to SO3 conversion rate, %vol	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%
Total Amount of SO2 converted to SO3, lb/h	0.66	0.53	0.41	0.61	0.50	0.39	0.60	0.49	0.38	0.54	0.44	0.35
Maximum Stack H2SO4 (assuming 100% conversion from SO3 to H2SO4), lb/h	1.01	0.81	0.64	0.94	0.76	0.60	0.92	0.74	0.59	0.82	0.68	0.53

Notes.

1. The emissions estimates shown in the table are for Simple Cycle GE-7FA Gas Turbines
2. The dry air composition used is 0.98% Ar, 78.03% N2 and 20.99%O2
3. ISO conditions are defined as 59 F, 14.696 psia and 60% RH, Norm conditions are defined as 0 C, 1.103 bar
4. All ppm values are based on CH4 calibration gas
5. The CTG performance is provided by General Electric dated 12/10/2007
6. Emission values at part loads and base loads are based on the JEA Kennedy guarantee provided by GE and TCEC Unit 1 permit guarantee respectively
7. The front half catch of particulate emissions is assumed to be half the amount of the front and back half catch. estimate and B&V's estimate was used in the summary table, i.e. the B&V estimates were adjusted, were applicable.

Emergency Diesel Engine Generator Manufacturer Data Sheet

Sales Model: 3512CDITA **Combustion:** DI **Aspr:** TA **Engine Power:** 2,206 HP
1500 W/F EKW 1560 W/O F EKW
Speed: 1,800 RPM **After Cooler:** ATAAC **Manifold Type:** DRY **Governor Type:** ADEM3 **After Cooler Temp(F):** 122 **Turbo Quantity:** 4 **Engine App:** GP **Turbo Arrangement:** Parallel **Hertz:** 60 **Engine Rating:** PGS **Strategy: Rating Type:** STANDBY **Certification:** EPA TIER-2 2006 -

EMISSIONS DATA

```
 EPA      TIER-2   2006 -
*************************************************** B5
Gaseous emissions data measurements are consistent with those
described in
EPA 40 CFR PART 89 SUBPART D and ISO 8178 for measuring HC, CO,
PM, and NOx

Gaseous emissions values are WEIGHTED CYCLE AVERAGES and are in
compliance
with the following non-road regulations:

LOCALITY              AGENCY/LEVEL            MAX LIMITS - g/kW-
hr
-----------------     ------------     --------------------------
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U.S. (incl Calif)     EPA/TIER-2       CO:3.5    NOx + HC:6.4
PM:0.2
```

ENGINE PERFORMANCE PARAMETERS @ RATED SPEED:

EXHAUST STACK DIAMETER	8 IN
WET EXHAUST MASS	21,100.4 LB/HR
WET EXHAUST FLOW (762.80 F STACK TEMP)	11,071.16 CFM
WET EXHAUST FLOW RATE (32 DEG F AND 29.98 IN HG)	4,321.00 STD CFM
DRY EXHAUST FLOW RATE (32 DEG F AND 29.98 IN HG)	3,958.78 STD CFM
FUEL FLOW RATE	105 GAL/HR

RATED SPEED "Not to exceed data"

GEN PWR EKW	PERCENT LOAD	ENGINE POWER BHP	TOTAL NOX (AS NO2) LB/HR	TOTAL CO LB/HR	TOTAL HC LB/HR	PART MATTER LB/HR	OXYGEN IN EXHAUST PERCENT	DRY SMOKE OPACITY PERCENT	BOSCH SMOKE NUMBER
1,500.0	100	2206	28.9800	3.9500	.7100	.2000	10.2000	.8000	1.2800
1,125.0	75	1662	14.7100	2.4400	.7800	.2000	11.5000	.9000	1.2800
750.0	50	1144	9.6800	3.3200	.7400	.3000	12.2000	1.9000	1.2800
375.0	25	632	7.2600	4.0700	.5800	.3800	13.2000	3.3000	1.2800
150.0	10	310	5.6300	3.8300	.6700	.2300	15.2000	2.0000	1.2800

RATED SPEED "Nominal Data"

GEN PWR EKW	PERCENT LOAD	ENGINE POWER BHP	TOTAL NOX (AS NO2) LB/HR	TOTAL CO LB/HR	TOTAL HC LB/HR	TOTAL CO2 LB/HR	PART MATTER LB/HR	OXYGEN IN EXHAUST PERCENT	DRY SMOKE OPACITY PERCENT	BOSCH SMOKE NUMBER
1,500.0	100	2206	24.1500	2.1900	.5300	2,262.3	.1400	10.2000	.8000	1.2800
1,125.0	75	1662	12.2600	1.3600	.5900	1,764.4	.1400	11.5000	.9000	1.2800
750.0	50	1144	8.0700	1.8400	.5500	1,242.0	.2100	12.2000	1.9000	1.2800
375.0	25	632	6.0500	2.2600	.4400	720.0	.2700	13.2000	3.3000	1.2800
150.0	10	310	4.6900	2.1300	.5000	410.8	.1600	15.2000	2.0000	1.2800

Reference
Number: DM8260 EPA TIER-2 2006 B5
Parameters
Reference: TM5739
GEN SET - PACKAGED - DIESEL
TOLERANCES:
AMBIENT AIR CONDITIONS AND FUEL USED WILL AFFECT THESE VALUES. EACH OF THE VALUES MAY VARY IN ACCORDANCE WITH THE FOLLOWING TOLERANCES.

ENGINE POWER	+/-	3%
EXHAUST STACK TEMPERATURE	+/-	8%
GENERATOR POWER	+/-	5%
INLET AIR FLOW	+/-	5%
INTAKE MANIFOLD PRESSURE - GAGE	+/-	10%
EXHAUST FLOW	+/-	6%
SPECIFIC FUEL CONSUMPTION	+/-	3%
FUEL RATE	+/-	5%
HEAT REJECTION	+/-	5%
HEAT REJECTION EXHAUST ONLY	+/-	10%

CONDITIONS:
ENGINE PERFORMANCE IS CORRECTED TO INLET AIR STANDARD CONDITIONS OF 99 KPA (29.31 IN HG) AND 25 DEG C (77 DEG F).

THESE VALUES CORRESPOND TO THE STANDARD ATMOSPHERIC PRESSURE AND TEMPERATURE IN ACCORDANCE WITH SAE J1995. ALSO INCLUDED IS A CORRECTION TO STANDARD FUEL GRAVITY OF 35 DEGREES API HAVING A LOWER HEATING VALUE OF 42,780 KJ/KG (18,390 BTU/LB) WHEN USED AT 29 DEG C (84.2 DEG F) WHERE THE DENSITY IS 838.9 G/L (7.002 LB/GAL).

THE CORRECTED PERFORMANCE VALUES SHOWN FOR CATERPILLAR ENGINES WILL APPROXIMATE THE VALUES OBTAINED WHEN THE OBSERVED PERFORMANCE DATA IS CORRECTED TO SAE J1995, ISO 3046-2 & 8665 & 2288 & 9249 & 1585, EEC 80/1269 AND DIN70020 STANDARD REFERENCE CONDITIONS.

ENGINES ARE EQUIPPED WITH STANDARD ACCESSORIES; LUBE OIL, FUEL PUMP AND JACKET WATER PUMP. THE POWER REQUIRED TO DRIVE AUXILIARIES MUST BE DEDUCTED FROM THE GROSS OUTPUT TO ARRIVE AT THE NET POWER AVAILABLE FOR THE EXTERNAL (FLYWHEEL) LOAD. TYPICAL AUXILIARIES INCLUDE COOLING FANS, AIR COMPRESSORS, AND CHARGING ALTERNATORS.

RATINGS MUST BE REDUCED TO COMPENSATE FOR ALTITUDE AND/OR AMBIENT TEMPERATURE CONDITIONS ACCORDING TO THE APPLICABLE DATA SHOWN ON THE PERFORMANCE DATA SET.

GEN SET - PACKAGED - DIESEL
ALTITUDE:
ALTITUDE CAPABILITY - THE RECOMMENDED REDUCED POWER VALUES FOR SUSTAINED ENGINE OPERATION AT SPECIFIC ALTITUDE LEVELS AND AMBIENT TEMPERATURES.

COLUMN "N" DATA - THE FLYWHEEL POWER OUTPUT AT NORMAL AMBIENT TEMPERATURE.

AMBIENT TEMPERATURE - TO BE MEASURED AT THE AIR CLEANER AIR INLET DURING NORMAL ENGINE OPERATION.
NORMAL TEMPERATURE - THE NORMAL TEMPERATURE AT VARIOUS SPECIFIC ALTITUDE LEVELS IS FOUND ON TM2001.

THE GENERATOR POWER CURVE TABULAR DATA REPRESENTS THE NET ELECTRICAL POWER OUTPUT OF THE GENERATOR.

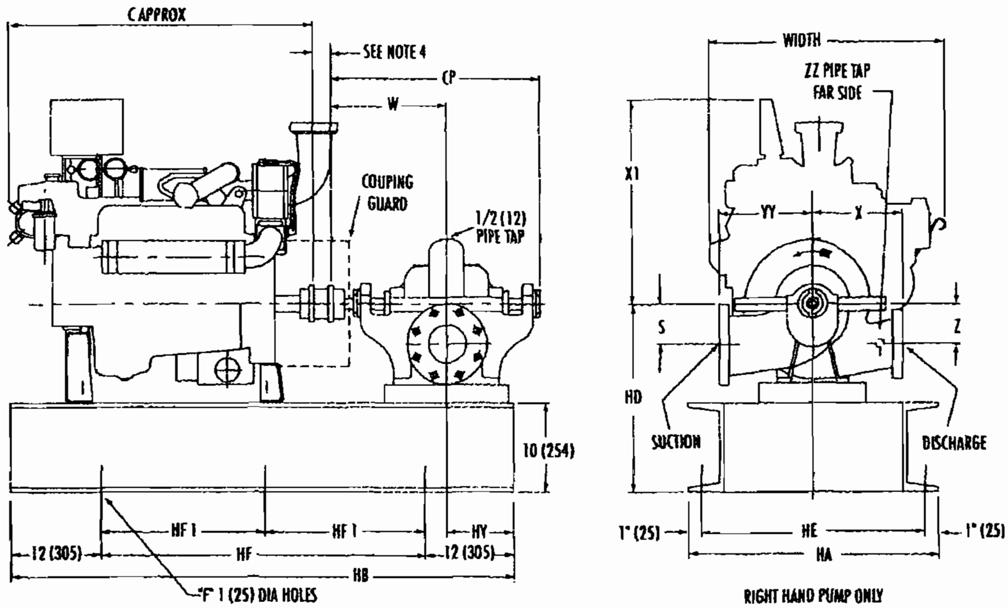
Emergency Diesel Fire Pump Manufacturer Data Sheet

JEA SEGS PROJECT

Supersedes Section 913 Page 324
Dated February 2005

AURORA MODEL 481, 491 & 492

SINGLE STAGE FIRE PUMPS
3306B–DIT & DITA CATERPILLAR DIESEL ENGINE DRIVE



PRELIM. PUMP SELECTION

STANDARD * 125# SUCTION AND DISCHARGE FLANGES					OPTIONAL 125# SUCTION FLANGE, 250# DISCHARGE FLANGE					OPTIONAL 250# SUCTION AND DISCHARGE FLANGES				
PUMP SIZE DISCH	MODEL	CASE BORE	SUCTION	POWER SERIES	S	W	X	Z	CP	YY	ZZ	HY	BASE LETTER
5	491	18A	8	NA	8-1/8 (206)	18-7/8 (479)	15 (381)	10-5/8 (270)	33-3/8 (847)	18-3/4 (476)	1	11-1/2 (292)	E1
6	481	15	8	5	6-3/4 (171)	18 (457)	14-1/4 (362)	6-3/4 (171)	32 (812)	16-3/4 (425)	1-1/4	8-1/2 (216)	E
6	481	15B	8		6-3/4 (171)	18 (457)	14-1/4 (362)	6-3/4 (171)	32 (812)	16-3/4 (425)	1-1/4	8-1/2 (216)	
6	481	18B	8		8 (216)	18 (457)	16 (406)	8 (216)	32 (812)	18 (457)	1-1/4	8-1/2 (216)	
6	481	18C	8		8 (216)	18 (457)	16 (406)	8 (216)	32 (812)	18 (457)	1-1/4	8-1/2 (216)	
6	481	20	8		8 (216)	18 (457)	15-3/4 (400)	8 (216)	32 (812)	18 (457)	1-1/4	8-1/2 (216)	
6	491	14A	10	NA	9-3/8 (238)	20-1/8 (511)	13-1/4 (336)	10 (254)	35-7/8 (911)	18 (457)	1	11-1/2 (292)	E2
6	491	14C	10		9-3/8 (238)	20-1/8 (511)	13-1/4 (336)	10 (254)	35-7/8 (911)	18 (457)	1	11-1/2 (292)	
6	491	18C	10		9-3/8 (238)	20-1/8 (511)	16 (406)	11-3/4 (298)	35-7/8 (911)	20 (508)	1	11-1/2 (292)	
6	491	19A	10		9-3/8 (238)	22-5/8 (574)	18 (457)	12-1/8 (308)	39-1/4 (996)	22 (558)	1	11-1/2 (292)	
6	491	12A	6		6-7/8 (175)	16-5/8 (422)	15-3/4 (400)	20-1/2 (520)	29-3/4 (755)	14 (355)	1	10-1/2 (266)	E
6	492	15	8		8-3/4 (222)	22-1/2 (571)	15 (381)	8-3/4 (222)	40-1/4 (1022)	15-1/2 (393)	1	10-1/2 (266)	E1
6	492	18	8		9-5/8 (244)	22-1/2 (571)	16 (406)	9-5/8 (244)	40-1/8 (1018)	16 (406)	1	10-1/2 (266)	
8	481	17B	10	5	8 (216)	18 (457)	17 (431)	8 (216)	32 (812)	17-3/4 (450)	2	8-1/2 (209)	E
8	481	21	10	6B	9-1/2 (241)	21-7/8 (555)	18 (457)	9-1/2 (241)	38 (964)	21 (533)	2	13-5/8 (346)	P
8	481	21A	10		9-1/2 (241)	21-7/8 (555)	18 (457)	9-1/2 (241)	38 (964)	21 (533)	2	13-5/8 (346)	
8	491	14A	12	NA	10-3/4 (273)	20-1/2 (520)	16 (406)	10-3/4 (273)	36-5/8 (930)	22 (558)	1	11-1/2 (292)	E3
8	491	18A	12		10-3/4 (273)	23-3/4 (603)	16 (406)	12-1/2 (317)	41-1/2 (1053)	22 (558)	1	11-1/2 (292)	
10	481	15C	10	6B	13-1/2 (343)	21-7/8 (555)	17 (431)	13-1/2 (343)	38 (964)	20 (508)	1-1/4	13-5/8 (346)	P
12	481	18	10	7	15 (381)	25-1/4 (641)	18 (457)	15 (381)	44 (1117)	23 (584)	2	13-5/8 (346)	

ENGINE MODEL	C	X1	WIDTH
3306B-DIT	66-7/8 (1695)	32-1/2 (824)	36 (914)
3306B-DITA	66-7/8 (1695)	34-3/8 (872)	36 (914)

BASE	HB	HA	HE	HF	HF1	HD	F
E	93 (2360)	29 (736)	27 (685)	69 (1751)	NA	25-1/4 (641)	4
E1	93 (2360)	29 (736)	27 (685)	69 (1751)	NA	28 (711)	4
E2	93 (2360)	29 (736)	27 (685)	69 (1751)	NA	29-1/2 (749)	4
E3	93 (2360)	29 (736)	27 (685)	69 (1751)	NA	32 (812)	4
P	96 (2436)	29 (736)	27 (685)	72 (1827)	NA	35-3/4 (907)	4

NOTES
1. All dimensions are in inches.
2. Dimensions may vary ± 3/8" (9).
3. Not for construction purposes unless certified.
4. Coupling Gap will vary with engine and pump model.
5. Suction & discharge flanges ANSI Standard flat face.
6. Refer to individual engine dimension print for reference point used to determine "C" dimension.
7. Left hand rotation not available.

* Standard flanges for 6-491-12A are 125# suction, 250 # discharge

AURORA®
Pentair Water

AURORA FIRE PUMPS

SELECTION TABLES

DIESEL DRIVEN HORIZONTAL SPLIT CASE

PRELIM. PUMP SELECTION

2000 GPM

DIESEL DRIVEN						
RATED PRESSURE (PSI)	REQUIRED ENGINE RATING		PUMP SIZE & MODEL	ENGINE MODEL	ENGINE HP	WEIGHT
	SPEED (RPM)	HORSE POWER (BHP)				
130	1460	263	8-481-21	CFP11E-F10	320	4248
	1750	235	6-481-18C	JW6H-UF38	252	4095
	1750	223	6-481-20	CFP83-F20	227	3822
	1750	230	8-481-21	JW6H-UF38	252	4160
	2100	238	6-491-18C	JW6H-UF60	240	4235
	2300	263	6-491-14A	JW6H-UF30	275	4639
135	1460	275	8-481-21	CFP11E-F10	320	4248
	1750	243	6-481-18C	JW6H-UF38	252	4095
	1750	235	6-481-20	JW6H-UF38	252	4042
	1750	243	8-481-21	JW6H-UF38	252	4160
	2100	249	6-491-18C	CFP11E-F10	331	4015
	2300	278	6-491-14A	JW6H-UF40	300	4639
140	1750	240	6-481-20	JW6H-UF38	252	4042
	1750	253	8-481-21	CFP83-F40	288	3940
	2100	261	6-491-18C	JW6H-UF40	300	4639
	2300	293	6-491-14A	JW6H-UF40	300	4639
145	1750	245	6-481-20	JW6H-UF38	252	4042
	1750	266	8-481-21	CFP83-F40	288	3940
	2100	272	6-491-18C	JW6H-UF40	300	4639
	2300	308	6-491-14A	JW6H-UF50	350	4689
150	1750	260	6-481-20	CFP83-F40	288	3822
	1750	275	8-481-21	CFP83-F40	288	3940
	2100	284	6-491-18C	JW6H-UF40	300	4639
	2300	325	6-491-14A	JW6H-UF50	350	4689
155	1750	306	6-491-19A	JW6H-UF60	360	4689
	1750	303	8-481-21	JW6H-UF60	360	3658
	2100	295	6-491-18C	JW6H-UF40	300	4639
160	1750	318	8-481-21	JW6H-UF60	360	3958
	2100	307	6-491-18C	JW6H-UF50	340	4276
165	1750	338	8-481-21	JW6H-UF60	360	3958
	2100	319	6-491-18C	JW6H-UF50	340	4276
170	1750	355	8-481-21	JW6H-UF60	360	3958
	2100	332	6-491-18C	JW6H-UF50	340	4276
175	1750	380	8-481-21	CFP11E-F20	424	4191
	2100	354	6-491-19A	JW6H-UF60	375	4689
180	1750	393	8-481-21	CFP11E-F20	424	4191
	2100	366	6-491-19A	JW6H-UF60	375	4689
185	1750	408	8-481-21	CFP11E-F20	424	4191
	2100	379	6-491-19A	JX6H-UF30	430	6480
190	1750	423	8-481-21	CFP11E-F20	424	4191
	2100	392	6-491-19A	JX6H-UF30	430	6480
195	2100	405	6-491-19A	JX6H-UF30	430	6480
200	2100	420	6-491-19A	JX6H-UF30	430	6480
210	2200	410	6-491-19A	RTF	RTF	RTF

PRELIMINARY ENGINE SELECTION

JW6H-UF50

Stationary Fire Pump Engine Driver
EMISSION DATA
EPA 40 CFR Part 60

6 *Cylinders*
Four *Cycle*
Lean *Burn*
Turbocharged & Raw Water Aftercoolec

500 PPM SULFUR #2 DIESEL FUEL								
RPM	BHP [3]	FUEL GAL/HR (L/HR)	GRAMS / HP- HR				EXHAUST	
			NMHC	NOx	CO	PM [4]	°F (°C)	CFM (m^3/min)
1760	300	14 (53)	0.31	5.20	1.01	0.23	866 (463)	1642 (46)
2100	340	16 (61)	0.36	4.31	0.40	0.17	788 (420)	2066 (59)
2350	350	17 (64)	0.52	3.67	0.48	0.21	806 (430)	2345 (66)

Notes:

1) *6081AF001 Base Engine Model manufactured by John Deere Corporation. For John Deere Emissions Conformance to EPA 40 CFR Part 60 see Page 2 of 2.*
2) *The Emission Warranty for this engine is provided directly to the owner by John Deere Corporation. A copy of the John Deere Emission Warranty can be found in the Clarke Operation and Maintenance Manual.*
3) *Engines are rated at standard conditions of 29.61In. (7521 mm) Hg barometer and 77°F (25° C) Inlet air temperature. (SAE J1349)*
4) *PM is a measure of total particulate matter, including PM_{10}.*

CLARKE

FIRE PROTECTION PRODUCTS
3133 EAST KEMPER ROAD
CINCINNATI, OH 45241

Fuel Gas Heater Data Sheet

FOR INFORMATION ONLY

NATCO

JEA
15701 West Beaver St.
Jacksonville, FL 32234

Quotation No.: 1S997009(07)
Date: 1/26/2007
Your Ref:
Job Site: Long Beach, NY

Attention: Kristin Anderson
904-665-7841

QUOTATION

Thank you for your inquiry. We appreciate this opportunity to quote on your requirements in accordance with the following specifications, prices and deliveries. This equipment is offered in accordance with National Tank Company's Terms and Conditions of Sale, a copy of which is attached.

ITEM (I) - INDIRECT GAS FIRED HEATER (Brandy Branch)

NOTE: FOR SEGS PROJECT USE KENNEDY DATA

SEGS WILL HAVE TWO (2) HEATERS SIMILAR TO THE ONE DESCRIBED BELOW

ITEM (2) - INDIRECT GAS FIRED HEATER (Kennedy)

One (1) NATCO INDIRECT FIRED WATER BATH HEATERS, built to the following design conditions:

A. PROCESS SPECIFICATIONS

Nominal Duty Rating	4.00MMBtu/hr
Calculated Duty	3.72MMBtu/hr
Process Fluid	Natural Gas
Specific Gravity	.589
Fluid Rate (@ max. pressure)	96 MMSCFD
Inlet Temperature	60°F
Inlet Pressure	450 psig
Allowable Pressure Drop	5 psi
Calculated Pressure Drop	3.7 psi
Outlet Temperature	95°F

Bath Temperature	190°F
Bath Capacity (Net Fill)	3,410 gallons
Bath Fluid	Ethylene Glycol and Water
Glycol Concentration (wt)	50 %
Thermal Efficiency (gross)	65 %
Thermal Efficiency (net)	72 %
Fuel Consumption @ Calculated Duty	5,723 scfh
Fuel Higher Heating Value	1,000 Btu/scf
Process Coil Heat Flux	5,531 Btu/hr ft^2
Firetube Heat Flux	12,093 Btu/hr ft^2
Firetube Heat Release Density	13,194 Btu/hr in^2

Note: Coil design is based on pipe in new and clean condition.

B. <u>MECHANICAL SPECIFICATIONS</u>

1. **Heater Shell**

Shell Diameter	72" OD
Shell Length	25'-0"
Design Code	API-12K (Not Stamped)
Design Pressure	0 psig
Maximum Allowable Working Pressure	0 psig
Design Temperature	250°F
Corrosion Allowance	None
Head Type	Flat
Head Material	SA516-70
Head Thickness	3/8"
Shell Material	SA-516-70
Shell Thickness	1/4"
Lifting Lugs	Two (2)
Saddles	Two (2)
Thermometer Connection	½" coupling
Drain2" coupling	
High Temperature Shutdown	1" coupling
Thermostat Connection	1" coupling
Low Level Shutdown	2" coupling
Preheat Coil Connection	1 1/2" coupling
Fill Connection	8" fabricated flange

2. **Firetube**

Removable	Yes
Material	A-53-B ERW
Thickness	.25"
Number of Firetubes	1
Outside Diameter	24"

	Effective Length	49.8'
	Surface Area	312.6 ft^2
	Pilot Lighting Port	2" with cap
	Radiography	None
3.	**Coil**	
	Design Code	ASME §VIII, Div. 1
	Corrosion Allowance	None
	Design Pressure	1,440 psig
	Hydrotest Pressure	1,872 psig for 1 hours
	Design Temperature	-20°F / +250°F
	Radiography	Full
	Stress Relieved	No
	Removable	Yes
	Pipe Straight Length	23'-0"
	Pipe Size/Schedule	3"/Sch 40
	Material	SA106-B
	Number of Parallel Paths	6
	Number of Passes per Flow Path	4
	Total Number of Tubes	24
	Available Tube Area	672.5 ft^2
	Required Tube Area	**619 ft^2**
	Coil Inlet Connection	10" 600# RF
	Coil Outlet Connection	10" 600# RF
	Coil Inlet Thermometer	1" coupling
	Coil Outlet Thermometer	1" coupling
	Coil Inlet Pressure Gauge	¾" coupling
	Coil Outlet Pressure Gauge	¾" coupling
4.	**Expansion Reservoir**	
	Diameter	30" OD
	Length	10'-0" Horizontal
	Design Code	Non-Code
	Design Pressure	0 psig
	Maximum Allowable Working Pressure	0 psig
	Design Temperature	250°F
	Corrosion Allowance	None
	Head Type	Flat
	Head Material	SA516-70
	Head Thickness	¼"
	Shell Material	SA-53-B ERW
	Shell Thickness	¼"
	Connection to Heater Shell	8" fabricated flange
	Fill Connection	8" fill hatch

5. **Burner Unit**

Type	Flame Arrestor
Quantity	1
Manufacturer/Model	Flameco Model SB38-24BLNS
Body Material	Aluminum
Maximum Heat Release (each)	6.15 MMBtu/hr
Supply Pressure at Burner	15 psig
Main Mixer	4" NS-160 w/ compound injector
Main Burner	5" 20F-1
Main Mixer Orifice	13/32"
Pilot Mixer	½" NATCO
Pilot Burner	½" NATCO RHSB
Pilot Orifice	No. 72
Noise Level	86 dba @ 3 ft.

6. **Pilot Sensing Unit**

Model	BASO H19NA-4
Automatic Ignitor	No
Power Required	None

7. **Stack**

Quantity	1
Diameter	24"
Height	20'-0"
Material	SA-53-B
Type	Flanged "Ell" with FLAMECO Down Draft Diverter, Rain Cap & Bird Screen, Aluminum

C. VESSEL ACCESSORIES

1. 1 1/2" fuel gas manifold, complete with:

   a. one (1) 1 1/2" Y-type strainer with valve.
   b. two (2) 2" Fisher 627R pressure regulators.
   c. one (1) 2" INVALCO DSG-203-415 control valves.
   d. two (2) 2" manual isolation valves
   e. one (1) 0-30 psig pressure gauge with isolation valve
   f. one (1) 0-200 psig pressure gauge with isolation valve

2. One (1) ¼" pilot gas manifold, complete with:
   a. two (2) ¼" manual isolation valve

b. one (1) ¼" Fisher 912 pressure regulator
c. one (1) 0-30 psig pressure gauge with isolation valve

3. One (1) 8" diameter bath fill hatch
4. One (1) extra-heavy fuel gas preheat coil
5. One (1) 2" drain with valve and plug
6. One (1) bath thermometer, 30°F-240°F, with separable socket
7. One (1) 24" liquid level gauge glass with cocks on expansion reservoir.
8. One (1) Kimray T12T bath temperature controller with separable socket.
9. One (1) Kimray T12T process temperature controller with separable socket.
10. One (1) Norriseal 1005P1 pneumatic low bath level switch
11. One (1) ¼" Fisher 67FR instrument pressure regulator
12. Stainless steel tubing and fittings

E. COATING

Heater shall be near white sandblasted and coated with one (1) coat primer coat of Carboline Carbozinc 11 primer. External surfaces protruding outside the insulation to receive one intermediate coat of Carboline 890 and one top coat of Carboline 134. Stacks to be commercial sandblasted and coated with one coat of NATCO standard Hi-Temp Aluminum.

F. INSULATION

Heater shell to be insulated with 1 1/2" thick fiberglass easy-wrap insulation and covered with 0.019" thick embossed aluminum jacketing and banded with ½" wide stainless steel bands.

G. SKID

None

H. LADDER AND PLATFORM

None

I. TESTING

1. Firetube welds to be tested with air and soap at 5 psig internal pressure.
2. Shell to be hydrotested to 3 psig with firetube, and coil bolted in place.

J. DOCUMENTATION

1. Two (2) of data manuals.
2. Two (2) sets of "For Information Only" drawings.
3. Mill test certificates (coil only if required).
4. Manufacturer's data reports (coil only).

K. ESTIMATED WEIGHT
Vessel estimated weight is 22,894 lbs.

NET PRICE, ITEM #2, FOB MANUFACTURER'S PLANT $101,722.00

OPTIONAL EQUIPMENT TO ITEM #2

A. NATCO THERMOCYCLE™ BAFFLE

"Thermocycle™ Baffle" which increases the Thermal Efficiency (Gross) from 65% to 75%. This efficiency increase will decrease fuel consumption from 50.1 MMSCF per year to 43.4 MMSCF per year. This reduction in fuel usage represents an annual savings of $33,500.00 at a fuel cost of $5.00 per Mcf.

NET PRICE ADDER, OPTION #2-A $5,265.00

B. NOISE REDUCTION BURNERS

One (1) NATCO designated Model SB40-24B-5CI (Ultra Low Noise) Burners in lieu of SB38-24B Burners per paragraph 5 in main body of quote. Reduce noise level from 86 dba at 3 ft to 75 dba at 3 feet.
Note: Firetube Economizer cannot be used with Ultra Low Noise Burner.

NET PRICE ADDER, OPTION #2-B $2,726.00

C. SKID

One (1) Simple Skid approx 8'-6" wide x 37'-0" long made using W6 x 15# Beam and no grating. Painted same as heater.

NET PRICE ADDER, OPTION #2-C $5,112.00

D. LADDER AND PLATFORM

One (1) Platform and Ladder for access to heater fill connection. Painted same as heater.

NET PRICE ADDER, OPTION #2-D $2,543.00

GENERAL NOTES

FOB Point: Electra, Texas

Estimated Delivery to Carrier: Heater #1 will deliver 22-24 weeks after receipt of order, plus drawing approval, if required. Heater #2 will deliver 20-22 weeks after receipt of order, plus drawing approval, if required. If both Heaters are ordered, delivery of Heater #2 will be 4-6 weeks after Heater #1.

Validity: Due to current fluctuation of steel and availability, NATCO reserves the right to review material costs and delivery at time of order.

Firm Price: Prices quoted above utilize NATCO completed standard drawings. Drawings can be submitted for information only. Modifications to these standards may require a price adjustment to accommodate material, engineering and drafting changes. Stated delivery may require an extension.

Terms: Net 30 days from date of invoice.

Freight: Estimated freight charges to job site will be provided later, if required. Please indicate with your order which of the following terms of shipment you prefer:

1) Freight collect;
2) Prepay and add freight (an administrative fee of 5% of the freight charge will be added; or
3) Other.

NATCO prefers to ship your order "Best Way" with freight charges "Collect".

Shipment Preparation: Unit will be shipped uncrated with all openings plugged or covered. If the Customer specifies the unit to be crated, an extra charge will then be made, depending on the type of crating specified.

Prices include preparation for shipment, to the extent that all loose fittings and accessories will be packed in suitable wooden approved crates or corrugated boxes. To facilitate shipment of unit, certain assembly items may be removed and shipped loose. Reassembly of such items in the field will be for the Customer's account.

Start-up and Commissioning: NATCO can provide qualified engineering assistance for the start-up and commissioning of the described equipment. For this service, as may be required, charges will be made based on NATCO's published rates in effect at time the service is performed.

Quality Assurance: NATCO operates a full Quality Assurance/Quality Control Program in accordance with the requirements of the ASME Code and ISO 9000 quality system.

The Quality Assurance Manager has responsibility for implementation of NATCO Quality System.

The Quality Policy Manual is available "on loan" for Client's review purposes.

The manual is available on "loan" for client's review purposes. NATCO Houston, Texas is in the process of obtaining ISO-9001 certification. Our NATCO-UK operation has received their ISO-9001 certification. Our NATCO-Canada, Electra, Texas and New Iberia, Louisiana operations have received their ISO-9002 certification.

Welding Specifications: This quotation is based on the use of NATCO's standard welding procedure specification (WPS), procedure qualifications (PQR), prequalified welders per ASME Code, Sec IX and AWS D1.1.

All of NATCO's standard welding will be done by the flux core arc welding (FCAW), submerged arc process welding (SAW), and the use of gas metal arc welding (GMAW).

NATCO's weld procedures are available upon request.

NATCO
TERMS AND CONDITIONS OF SALE

1. **Title and Risk of Loss.** Title and risk of loss pass to Purchaser Ex Works Seller's fabrication plant.

2. **Prices.** Prices quoted for products are based on receiving orders for the quantity specified. Prices quoted also assume Seller shall not be responsible for any duties, fees, licenses, permits, tariffs, or taxes.

3. **Validity.** Prices expire 30 days from quotation date, if not previously canceled in writing by Seller. Stock materials included in a quotation are subject to prior sale.

4. **Changes.** If Purchaser requests or causes a change in Seller's quoted schedule or method of engineering, fabrication, or shipment that results in delay or additional expense to Seller, all costs incurred shall be for the account of Buyer, including storage charges in the event of a suspension of fabrication or delivery. The delivery date shall be equitably adjusted when affected by any Purchaser change. In no event will a change be implemented without a signed change order issued by Buyer.

5. **Shipment/Delivery.** All prefabricated packages or skid-mounted assemblies shall be assembled in Seller's plant to the extent practicable. These assembled units shall be disassembled before shipping, but only to the extent required to facilitate the chosen means of transportation. All field reassembly necessary to place units in operable condition shall be done by and at Buyer's expense.

All materials and parts shall be packaged and shipped at the lowest acceptable rate by common carrier or any other method deemed necessary or advisable by Seller. The terms of shipment of Seller's goods shall be at Buyer's election based on Seller's quotation.

6. **Force Majeure.** Seller shall not be liable for delays due to unforeseeable causes or events beyond its reasonable control. Seller shall give Buyer written notice within 7 days of commencement of the cause or event and shall promptly resume performance upon expiration of the cause or event.

7. **Ingress/Egress.** All sales and purchase prices assume continuous use of and free ingress and egress to Purchaser's site by Seller's personnel on all-weather roads.

8. **Warranty.** Seller warrants new products of its manufacture to be free from defective workmanship and material for a period of 12 months from date of equipment startup or 18 months from date of Seller's transmittal of notice of readiness for shipment to Buyer, whichever period expires first, provided Purchaser subjects the equipment only to the operating conditions specified by Buyer when the order is placed and in accordance with Seller's written operating instructions, if any. Seller does not warrant components manufactured by others but will use its best efforts to assign any component manufacturer's warranty or guarantee to Buyer. In the event of a breach of this warranty, Seller shall, at its option, repair the defective part or furnish a replacement part Ex Works Seller's fabrication plant. Equipment performance guarantees, if any, are specifically limited to those described in Seller's quotation. **SELLER MAKES NO WARRANTY WITH RESPECT TO PARTS REQUIRING REPLACEMENT DUE TO NORMAL WEAR AND TEAR, USED EQUIPMENT, OR PAINTING/COATING/LINING. EXCEPT FOR THE WARRANTY EXPRESSLY STATED ABOVE, THERE ARE NO OTHER WARRANTIES AND NONE SHALL BE IMPLIED BY LAW INCLUDING THOSE OF MERCHANTABILITY AND FITNESS FOR A PARTICULAR PURPOSE.**

9. **Service Warranty.** Service work is warranted for 180 days from the original service date. **NO OTHER WARRANTIES, EXPRESS OR IMPLIED, ARE GIVEN.**

10. **Indemnity.** To the extent of its negligence or fault, each party agrees to release, indemnify, and hold harmless the other party from and against all causes of action, claims, damages, demands, liability, losses, and suits of every type and character, including all litigation expenses, court costs, and attorney's fees, arising out of or related in any way to the work contemplated by this sale ("Claims") that are asserted for personal injury, death, or property damage. Seller's liability for damages to Buyer's tangible property shall be limited to repair or replacement of the damaged part or parts of the goods furnished hereunder. In no event shall Seller be liable to Buyer for delays, curtailment of plant operations, process failure, pollution, loss of profits, costs for removing any parts or equipment to be repaired or replaced, transportation, or installation charges in connection with the repair, replacement, or servicing of any parts or equipment. Any drawings or general information furnished to aid Buyer in the installation or erection of goods sold are furnished for Buyer's convenience only, are not warranted by Seller, and Seller shall incur no liability whatsoever arising there from.

Neither party shall be liable for any special, indirect, speculative or consequential damages of any type or character (including, but not limited to, loss of profit, use, or production) arising from or related in any way to performance hereunder.

Buyer will release, indemnify and will hold Seller harmless from any Claims regarding pollution regardless of source.

Seller shall not be liable for the structural design or operating performance of equipment manufactured according to designs, drawings, or specifications of Buyer or a third party acting for Buyer; this provision shall also include shop drawings made by Seller and approved by Buyer.

11. **Cancellation for Convenience.** Where cancellation of this sale or any work ordered in connection with this sale is for Buyer's sole convenience, Buyer shall ratably reimburse Seller for all work performed prior to Seller's receipt of Buyer's cancellation notice and all reasonable costs incurred in effecting cancellation.

12. **Limitation of Liability.** To the fullest extent permitted by applicable law and to the extent not specifically negotiated and noted elsewuere, Seller's total liability, in the aggregate, to Buyer or anyone or any entity claiming by, through, or under Buyer for any Claims from any cause or causes including, but not limited to, any breach of contract, negligence, strict liability, or express or impkied warranty shall not exceed 25% of the value of the services rendered or work performed by Contractor.

13. **Intellectual Property** Unless otherwise specifically stipulated elsewhere, Seller shall pay all royalties and license fees and assume all costs and expenses incident to the use of any invention, composition, process, device, article, appliance, or design that is the subject of patent rights, copyrights, or other legal rights of ownership as are applicable to the goods manufactured by Seller and furnished hereunder. Seller shall indemnify and hold harmless Buyer from and against all Claims, including attorney's fees, arising out of any infringement of these rights during or after completion of performance and shall defend all Claims in connection with any alleged infringement of these

rights. Seller must be notified promptly in writing and given authority, information, and assistance (at Seller's expense) for the defense, and Seller shall pay all sums and costs awarded against Buyer, not to exceed the price paid or due to Seller for the equipment held to infringe. Seller shall have no liability for infringement Claims related to its equipment, if the equipment is used for purposes other than those designed by the Seller or if infringement Claims arise out of the use of Seller's equipment in conjunction with other equipment not supplied by Seller. Unless the use of an infringing item or part is enjoined, Seller shall, at its own expense and option, either (i) procure for Purchaser the right to continue using the item or part, (ii) replace with non-infringing items, (iii) modify it so that it becomes non-infringing, or (iv) remove the items and refund the purchase price thereof. These provisions shall not apply to any item manufactured pursuant to Buyer's design or to infringement Claims for equipment furnished but not manufactured by Seller. Further, Seller assumes no liability and shall be indemnified by Buyer for any infringement associated with any item manufactured pursuant to Buyer's design. The foregoing constitutes the entire understanding and agreement between the parties regarding patent infringement issues.

14. **Purchaser's Financial Condition.** Seller reserves the right to cancel shipment at any time prior to delivery of products without further obligation or liability on Seller's part, if Purchaser's credit or financial condition is unsatisfactory to Seller.

15. **Payment Terms.** Terms are net 30 days from date of invoice. Interest will be charged on past due accounts at the maximum lawful rate. All fees, costs, and expenses incurred (legal or otherwise) by Seller in pursuit of monies due, shall be reimbursed by Buyer. Regardless of the actual shipment date, Sellershall issue an invoice at time of notification of readiness for shipment.

Seller shall issue an invoice at time of notification of readiness for shipment, although Purchaser requests that shipment be delayed.

16. **Inspection.** Any inspection or acceptance required by Buyer shall take place at Seller's fabrication plant; however, it is expressly understood that inspection and acceptance at the fabrication plant shall not relieve Seller of the Warranty responsibilities found in these terms and conditions.

Buyer shall be responsible and pay for all permit and licenses fees required by any law, order, rule, or regulation of any authority having jurisdiction relative to inspection of the material or labor sold hereunder, including boiler, electrical, and other inspections.

17. **Subcontractors.** Seller may subcontract all orders.

18. **Environmental Responsibility.** Buyer shall be solely responsible for management of any hazardous or toxic waste or material or any component thereof generated during ***cleaning or servicing*** of Buyer's equipment ("Waste"); the foregoing does not include the management of any hazardous or toxic waste or material or any component thereof that is owned by Seller and in its possession and control. As used in this provision, the term "management" and its derivatives include, but are not limited to, transporting, collecting, processing, treating, using, reselling, or storing. Seller is not permitted, certified, or otherwise licensed to manage or dispose of Waste generated when ***cleaning or servicing*** Buyer's equipment. **Buyer shall assume sole responsibility for the Waste and shall release, indemnify and hold harmless Seller from and against all Claims that result in alleged or actual pollution or other damage (including personal injury, death, or property damage) that arises out of or is related in any way to the Waste.**

19. **Storage.** In the event Buyer delays shipment for any reason and desires to store the equipment on Seller's premises, Buyer agrees to and shall execute Seller's Storate Agreement.

20. **Assignment.** Any transaction resulting from this order shall not be assignable by either party without the prior written consent of the other party, except that any transaction may be assigned without consent to the successor of either party acquiring all or substantially all of the business or assets of that party.

21. **Controlling Terms.** These terms and conditions shall prevail over all other terms and conditions unless an officer of Seller waives the conflict in writing.

22. **Applicable Law.** The validity of these terms and conditions, all related documents, and all Claims arising hereunder shall be construed, interpreted, and governed in accordance with the laws of the State of Texas. The parties agree that for purposes of all Claims that arise out of or are related in any way to the subject matter of this contract that proper venue shall be Harris County, Texas.

With respect to CHEMICAL SALES, NATCO's Terms and Conditions of Chemical Sales shall apply.

Please direct all inquires concerning this proposal to Mr. Gary Pruitt in our Brookhaven, MS sales office, telephone (601) 833-3261.

NATCO

LeRoy Childers

cc: File
NATCO Brookhaven, MS
NATCO Houston, TX
q:\Transmission\1S's\1S997(Quotes 2007)\1S997009\misc\1S997009

Appendix C
Emission Calculations

JEA

Greenland Energy Center PSD Application

Summary of Potential to Emit for Criteria Pollutants (Simple Cycle Configuration)

(Tons per year)

Table C-1

	CO	NO_x	PM/PM_{10}	SO_2	VOC	H_2SO_4	Pb	Hg	Fluorides	H_2S	Total Reduced Sulfur
Units 1 and 2 SCCTs [*]	67.70	340.20	71.00	28.81	10.85	11.03	0.00	0.00	0.00	0.00	0.00
Emergency Diesel Engine Generator	0.45	3.33	0.02	0.00	0.08	0.00	0.00	0.00	0.00	0.00	0.00
Emergency Diesel Fire Pump	0.07	0.57	0.03	0.00	0.08	0.00	0.00	0.00	0.00	0.00	0.00
Fuel Gas Heater	2.01	2.41	0.19	0.02	1.27	0.02	0.00	0.00	0.00	0.00	0.00
2 ULSFO Tanks					0.71						
TOTAL (SCCT Operations)	70.24	346.51	71.25	28.82	13.00	11.05	0.00	0.00	0.00	0.00	0.00
Future CCCT Operations	251.89	142.58	215.41	72.65	34.40	43.49					
PSD SER	100	40	25/15	40	40	7	0.6	--	3	10	10
PSD Review Required Based on CCCT Emissions?	YES	YES	YES	YES	NO	YES	NO	--	NO	NO	NO

Notes [ ]:

* PTE is the expected emissions from combustion turbine operation at 3,500 hours per CTG per year on natural gas alone or the combination of natural gas/ULSFO (3,000 hours per CTG per year on natural gas and 500 hours per CTG per year on ULSFO); whichever is greater. This operational scenario occurs post-construction of the natural gas pipeline and results in a PTE greater than the PTE from firing ULSFO 1,000 hours per year per CTG prior to the natural gas pipeline construction.

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Units 1 and 2 SCCT Parameters

Pre- Onsite Natural Gas Availability

Emissions Calculation

Basis:

Unit Type	GE 7FA	
Number of Turbines	2	
Fuel	ULSFO	
Fuel Burn Rate	1,994.1	MBtu/hr [1]
Hours of Operations	1,000	hr/yr per unit

Table C-2: Units 1 and 2 ULSFO SCCT Emissions

Pollutant	ULSFO			Potential to Emit (tpy)
	Emission Factor (lb/MBtu)		Mass Emission (lb/hr/unit)	
CO	0.0192	[1]	38.2	38.2
NO_x	0.1652	[1]	329.4	329.4
PM_{10}	0.0171	[1]	34.0	34.0
SO_2	0.0012	[1]	2.5	2.5
VOC	0.0022	[1]	4.3	4.3
H_2SO_4	0.0005	[1]	0.9	0.9
Lead	0.000014	[2]	0.0	0.0
Mercury	0	[3]	0	0.0
Fluorides	0	[3]	0	0.0
H_2S	0	[3,4]	0	0.0
Total Reduced Sulfur	0	[3,4]	0	0.0
CO_2	157	[2,5]	313,074	313,074

Notes [ ]:

1. Based on performance data at 100% load and ISO conditions (59 °F, 60% Relative Humidity) as contained in Appendix B.
2. USEPA, AP-42, Fifth Edition, Vol. I. Chapter 3 "Stationary Internal Combustion Sources", Section 3.1 "Stationary Gas Turbines", April 2000. Table 3.1-2a "Emission Factors for Criteria Pollutants and Greenhouse Gases from Stationary Gas Turbines".
3. Emissions are insignificant and assumed to be zero.
4. All sulfur contained in the natural gas was assumed to be emitted as either SO_2 or H_2SO_4.
5. CO_2 emissions are being listed for informational purposes only.

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Units 1 and 2 SCCT Parameters
Post-Onsite Natural Gas Availability
Emissions Calculation

Basis:

Unit Type	GE 7FA		Unit Type	GE 7FA
Number of Turbines	2		Number of Turbines	2
Fuel	Natural Gas		Fuel	ULSFO
Fuel Burn Rate	1,805.7 MBtu/hr [1]		Fuel Burn Rate	1,994.1 MBtu/hr [1]
Hours of Operations	3,000 hr/yr per unit ←	Scenario 1	→ Hours of Operations	500 hr/yr per unit
Hours of Operations	3,500 hr/yr per unit ←	Scenario 2	→ Hours of Operations	0 hr/yr per unit

Table C-3: Units 1 and 2 Natural Gas SCCT Emissions

Pollutant	Natural Gas				ULSFO			PTE Total (tpy)[2]
	Emission Factor (lb/MBtu)	Mass Emission (lb/hr/unit)	Potential to Emit for 3,000 hours (tpy)	Potential to Emit for 3,500 hours (tpy)	Emission Factor (lb/MBtu)	Mass Emission (lb/hr/unit)	Potential to Emit on 500 hours (tpy)	
CO	0.0090 [1]	16.2	48.6	56.7	0.0192 [1]	38.2	19.1	67.7
NO_x	0.0324 [1]	58.5	175.5	204.8	0.1652 [1]	329.4	164.7	340.2
PM_{10}	0.0100 [1]	18.0	54.0	63.0	0.0171 [1]	34.0	17.0	71.0
SO_2	0.0046 [1]	8.2	24.7	28.8	0.0012 [1]	2.5	1.2	28.8
VOC	0.0016 [1]	2.9	8.7	10.2	0.0022 [1]	4.3	2.2	10.9
H_2SO_4	0.0017 [1]	3.2	9.5	11.0	0.0005 [1]	0.9	0.5	11.0
Lead	No Data [3]	0	0.0	0.0	0.000014 [3]	0.0	0.0	0.0
Mercury	0 [4]	0	0.0	0.0	0 [4]	0	0.0	0.0
Fluorides	0 [4]	0	0.0	0.0	0 [4]	0	0.0	0.0
H_2S	0 [4, 5]	0	0.0	0.0	0 [4, 5]	0	0.0	0.0
Total Reduced Sulfur	0 [4, 5]	0	0.0	0.0	0 [4, 5]	0	0.0	0.0
CO_2	110 [3,6]	198,627	595,881	695,195	157 [3,6]	313,074	156,537	752,418

Notes [ ]:

1. Based on performance data at 100% load and ISO conditions (59 °F, 60% Relative Humidity) as contained in Appendix B.
2. PTE Total based on the higher of firing either 3,500 hours per year on natural gas or 3,000 hours per year on natural gas with 500 hours per year on ULSFO.
3. USEPA, AP-42, Fifth Edition, Vol. I. Chapter 3 "Stationary Internal Combustion Sources", Section 3.1 "Stationary Gas Turbines", April 2000. Table 3.1-2a "Emission Factors for Criteria Pollutants and Greenhouse Gases from Stationary Gas Turbines".
4. Emissions are insignificant and assumed to be zero.
5. All sulfur contained in the natural gas was assumed to be emitted as either SO_2 or H_2SO_4.
6. CO_2 emissions are being listed for informational purposes only.

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Units 1 and 2 CCCT Parameters

Possible Future Combined Cycle Facility

Estimated Emissions Calculation

Basis:

Unit Type	GE 7FA	
Number of Turbines	2	
Fuel	Natural Gas	ULSFO
CTG Fuel Burn Rate	1,786.7 MBtu/hr [1]	1,961.0 MBtu/hr [1]
Duct Burner Fuel Burn Rate	200 MBtu/hr [1]	200 MBtu/hr [1]
Hours of Operations	8,260 hr/yr/unit ← Scenario 1 →	500 hr/yr/unit
Hours of Operations	8,760 hr/yr/unit ← Scenario 2 →	0 hr/yr/unit

Table C-4: Units 1 and 2 Natural Gas CCCT Emissions

Pollutant	Natural Gas		ULSFO		PTE Total
	Mass Emission (lb/hr/unit)	Potential to Emit (tpy)	Mass Emission (lb/hr/unit)	Potential to Emit (tpy)	(tpy)[2,6]
CO	28.2 [1]	232.52	38.8 [1]	19.38	251.89
NO_x	13.1 [1]	108.05	69.0 [1]	34.52	142.58
PM_{10}	23.7 [1]	195.76	39.3 [1]	19.65	215.41
SO_2	8.3 [1, 6]	72.65	3.2 [1]		72.65
VOC	3.9 [1]	31.80	5.2 [1]	2.60	34.40
H_2SO_4	5.0 [1, 6]	43.49	1.6 [1]		43.49
Lead	0 [3]	0.0	0 [3]	0.0	0.00
Mercury	0 [4]	0.0	0 [4]	0.0	0.00
Fluorides	0 [4]	0.0	0 [4]	0.0	0.00
H_2S	0 [4, 5]	0.0	0 [4, 5]	0.0	0.00
Total Reduced Sulfur	0 [4, 5]	0.0	0 [4, 5]	0.0	0.00

Notes [ ]:

1. Based on preliminary performance data at 100% load and ISO conditions (59 °F, 60% Relative Humidity).
2. PTE Total based on the higher of firing either 8,760 hours per year on natural gas or 8,260 hours per year on natural gas with 500 hours per year on ULSFO.
3. USEPA, AP-42, Fifth Edition, Vol. I. Chapter 3 "Stationary Internal Combustion Sources", Section 3.1 "Stationary Gas Turbines", April 2000. Table 3.1-2a "Emission Factors for Criteria Pollutants and Greenhouse Gases from Stationary Gas Turbines".
4. Emissions are insignificant and assumed to be zero.
5. All sulfur contained in the natural gas was assumed to be emitted as either SO_2 or H_2SO_4.
6. Worst case SO_2 and H_2SO_4 PTE occur when natural gas is combusted 8,760 hours per year.

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Emergency Diesel Engine Generator Parameters

Emissions Calculation and Stack Parameters Information

Basis:

Power Rating	2,206 HP[1]	
Heat Input	14.70 MBtu/hr	
Heating Value	140,000 Btu/gal[2]	
Fuel Burn Rate	105 gal/hr[1]	24,150 gal/yr
Hours of Operation	230 hrs/yr	

Stack Exit Conditions [1]:

Exhaust Flow Rate	11,071 acfm		
Exhaust Exit Velocity	528.60 ft/sec	161.12 m/sec	
Exhaust Temperature	762.8 °F	679.15 K	
Stack Diameter	8 in	0.67 ft	0.2032 m
Stack Height	24 ft	7.32 m	

Table C-5: Emergency Diesel Engine Generator Emissions

Pollutant	Emission Rate			Potential to Emit (total)
	g/sec	lb/hr		ton/yr
CO	0.4977	3.9500	[1]	4.54E-01
NO_x	3.6514	28.9800	[1]	3.33E+00
PM/PM_{10}	0.0252	0.2000	[1]	2.30E-02
SO_2	0.0028	0.0222	[3]	2.55E-03
VOC	0.0895	0.7100	[1]	8.17E-02
H_2SO_4	0.0043	0.0340	[4]	3.91E-03
Lead	0	0	[5]	0.00E+00
Mercury	0	0	[5]	0.00E+00
Fluorides	0	0	[5]	0.00E+00
H_2S	0	0	[5]	0.00E+00
Total Reduced Sulfur	0	0	[5]	0.00E+00

Operating Scenarios:

24-hr per day operation for short-term emissions
Annual hours of operation given above used for annualizing emissions

Table C-6: Emergency Diesel Engine Generator Modeling Parameters

Pollutant	Emission Rate for the Applicable Averaging Period									
	1-hr		3-hr		8-hr		24-hr		Annual	
	g/sec	lb/hr	g/sec	lb/hr	g/sec	lb/hr	g/sec	lb/hr	g/sec	lb/hr
CO	4.977E-01	3.950E+00	–	–	4.977E-01	3.950E+00	–	–	–	–
NO_x	–	–	–	–	–	–	–	–	9.587E-02	7.609E-01
PM/PM_{10}	–	–	–	–	–	–	2.520E-02	2.000E-01	6.616E-04	5.251E-03
SO_2	–	–	2.795E-03	2.218E-02	–	–	2.795E-03	2.218E-02	7.339E-05	5.825E-04

Notes [ ]:

1. Vendor data - Caterpillar Model 3512 CDITA included in Appendix B
2. Assumed fuel oil heating value of 140,000 Btu/gal. USEPA, AP-42, Fifth Edition, Vol. I, Appendix A "Miscellaneous Data and Conversion Factors". September 1985.
3. Ultra low sulfur fuel oil, 0.0015%(wt).
4. Assumed 100% conversion of SO_2 to H_2SO_4.
5. Emissions are insignificant and assumed to be zero.

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Emergency Diesel Fire Pump Parameters

Emissions Calculation and Stack Parameters Information

Basis:

Power Rating	350 BHP[1]	
Heat Input	2.38 MBtu/hr	
Heating Value	140,000 Btu/gal[2]	
Fuel Burn Rate	17.0 gal/hr[1]	6,800 gal/yr
Hours of Operation	400 hrs/yr	

Stack Exit Conditions [1]:

Exhaust Flow Rate	2,345 acfm		
Exhaust Exit Velocity	286.63 ft/sec	87.37 m/sec	
Exhaust Temperature	806 °F	703.15 K	
Stack Diameter	5 in	0.42 ft	0.13 m
Stack Height	15.17 ft	4.62 m	

Table C-7: Emergency Diesel Fire Pump Emissions

Pollutant	Outlet Conditions	Emission Rate			Potential to Emit
	g/bhp-hr	g/sec	lb/hr		ton/yr
CO	0.48	0.0467	0.3704	[1]	7.41E-02
NO_x	3.67	0.3568	2.8318	[1]	5.66E-01
PM/PM_{10}	0.21	0.0204	0.1620	[1]	3.24E-02
SO_2	4.65E-03	0.0005	0.0036	[3]	7.18E-04
VOC	0.52	0.0506	0.4012	[1]	8.02E-02
H_2SO_4	0.01	0.0007	0.0055	[4]	1.10E-03
Lead	0	0	0	[5]	0.00E+00
Mercury	0	0	0	[5]	0.00E+00
Fluorides	0	0	0	[5]	0.00E+00
H_2S	0	0	0	[5]	0.00E+00
Total Reduced Sulfur	0	0	0	[5]	0.00E+00

Operating Scenarios:

24-hr per day operation for short-term emissions

Annual hours of operation given above used for annualizing emissions

Table C-8: Emergency Diesel Fire Pump Modeling Parameters

Pollutant	Emission Rate for the Applicable Averaging Period									
	1-hr		3-hr		8-hr		24-hr		Annual	
	g/sec	lb/hr	g/sec	lb/hr	g/sec	lb/hr	g/sec	lb/hr	g/sec	lb/hr
CO	4.667E-02	3.704E-01	–	–	4.667E-02	3.704E-01	–	–	–	–
NO_x	–	–	–	–	–	–	–	–	1.629E-02	1.293E-01
PM/PM_{10}	–	–	–	–	–	–	2.042E-02	1.620E-01	9.323E-04	7.399E-03
SO_2	–	–	4.526E-04	3.592E-03	–	–	4.526E-04	3.592E-03	2.066E-05	1.640E-04

Notes [ ]:

1. Vendor data - Aurora Model 491 (2,350 RPM), included in Appendix B
2. Assumed fuel oil heating value of 140,000 Btu/gal. USEPA, AP-42, Fifth Edition, Vol. I. Appendix A "Miscellaneous Data and Conversion Factors". September 1985.
3. Ultra low sulfur fuel oil, 0.0015%(wt).
4. Assumed 100% conversion of SO_2 to H_2SO_4.
5. Emissions are insignificant and assumed to be zero.

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Fuel Gas Heater

Emissions Calculation and Stack Parameters Information

Basis:

Heat Input	5.84 MBtu/hr[1]
Heating Value	1,020 Btu/scf[2]
Fuel Burn Rate	0.0057 mmscf/hr[1]
Hours of Operation	8,760 hrs/yr

Stack Exit Conditions [1]:

Exhaust Flow Rate	1,374 acfm		
Exhaust Exit Velocity	7.29 ft/sec	2.22 m/sec	
Exhaust Temperature	1,165 °F	902.59 K	
Stack Diameter	24 in	2.00 ft	0.61 m
Stack Height	20 ft	6.10 m	

Table C-9: Fuel Gas Heater Emissions

Pollutant	AP-42 EF lb/mmscf	Emission Rate g/sec	Emission Rate lb/hr		Potential to Emit ton/yr
CO		0.0580	0.4600	[1]	2.01E+00
NO_x		0.0693	0.5500	[1]	2.41E+00
PM/PM_{10}	7.60	0.0055	0.0435	[3]	1.90E-01
SO_2	6.00E-01	0.0004	0.0034	[3]	1.50E-02
VOC		0.0365	0.2900	[1]	1.27E+00
H_2SO_4		0.0007	0.0053	[4]	2.30E-02
Lead		0	0	[5]	0.00E+00
Mercury		0	0	[5]	0.00E+00
Fluorides		0	0	[5]	0.00E+00
H_2S		0	0	[5]	0.00E+00
Total Reduced Sulfur		0	0	[5]	0.00E+00

Operating Scenarios:
24-hr per day operation for short-term emissions
Annual hours of operation given above used for annual emissions

Table C-10: Fuel Gas Heater Modeling Parameters

Pollutant	Emission Rate for the Applicable Averaging Period									
	1-hr		3-hr		8-hr		24-hr		Annual	
	g/sec	lb/hr	g/sec	lb/hr	g/sec	lb/hr	g/sec	lb/hr	g/sec	lb/hr
CO	5.796E-02	4.600E-01	–	–	5.796E-02	4.600E-01	–	–	–	–
NO_x	–	–	–	–	–	–	–	–	6.930E-02	5.500E-01
PM/PM_{10}	–	–	–	–	–	–	5.480E-03	4.349E-02	5.480E-03	4.349E-02
SO_2	–	–	4.326E-04	3.434E-03	–	–	4.326E-04	3.434E-03	4.326E-04	3.434E-03

Notes [ ]:
1. Vendor data - NATCO Indirect Fired Water Bath Heater, included in Appendix B
2. Assumed natural gas heating value of 1,020 Btu/scf. USEPA, AP-42, Fifth Edition, Vol. I. Appendix A "Miscellaneous Data and Conversion Factors". September 1985.
3. USEPA AP-42 Table 1.4-2
4. Assumed 100% conversion of SO_2 to H_2SO_4.
5. Emissions are insignificant and assumed to be zero.

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ULSFO Storage Tanks

Table C-11: VOC Emissions from ULSFO Storage Tanks

CTG ULSFO Usage Rate at ISO Conditions	102,310	lb/hr
Operational Hours per CTG per year	1000	hrs
Worst Case ULSFO use per Year for 2 CTGs	204,620,000	lbs/yr
ULSFO Density	6.79	lb/gal

Annual Throughput of ULSFO	3.01E+07	gallons
Annual Throughput per tank	1.51E+07	gallons
From TANKS	**713.65**	**lbs/yr/tank**

Note: Worst case emissions occur during the pre-onsite natural gas pipeline scenario

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Hazardous Air Pollutants
Pre- Onsite Natural Gas Availability

Table C-12: Emissions Calculations with CTGs Firing Natural Gas and ULSFO

INPUTS

No. of CTGs
2

Heat Input (MBtu/hr)				
CTG (GAS) [1]	CTG (ULSFO) [1]	Fire Pump	Emergency Engine	Fuel Heater
1805.7	1994.1	2.38	14.70	5.837

Hours of Operation per Unit				
CTG (GAS)	CTG (ULSFO)	Fire Pump	Emergency Engine	Fuel Heater
0	1000	400	230	0

	Combustion Turbines							Fire Pump			Emergency Diesel Engine Generator			Fuel Heater				
Pollutant	CTG (Natural Gas) Emission factor [2] lb/Mbtu	2 CTGs Natural Gas PTE (lb/hr)	2 CTGs Natural Gas PTE (tpy)	CTG (ULSFO) Emission factor [3] lb/Mbtu	2 CTGs ULSFO PTE (lb/hr)	2 CTGs ULSFO PTE (tpy)	2 CTGs Total NG+ULSFO PTE (lb/hr)	Fire Pump E.F.[4] lb/Mbtu	Fire Pump PTE (lb/hr)	Fire Pump PTE tpy	Emer Eng E.F.[5] lb/Mbtu	Emer Eng PTE (lb/hr)	Emer Eng PTE tpy	Fuel Heater E.F.[6] lb/Mbtu	Fuel Heater PTE (lb/hr)	Fuel Heater PTE tpy	Total PTE tpy	
1,3-Butadiene	4.30E-07	1.55E-03	0.00E+00	1.60E-05	6.38E-02	3.19E-02	6.54E-02	3.91E-05	9.31E-05	1.86E-05							3.19E-02	
Acetaldehyde	4.00E-05	1.44E-01	0.00E+00				1.44E-01	7.67E-04	1.83E-03	3.65E-04	2.52E-05	3.70E-04	4.26E-05				4.08E-04	
Acrolein	6.40E-06	2.31E-02	0.00E+00				2.31E-02	9.25E-05	2.20E-04	4.40E-05	7.88E-06	1.16E-04	1.33E-05				5.74E-05	
Arsenic				1.10E-05	4.39E-02	2.19E-02	4.39E-02										2.19E-02	
Benzene	1.20E-05	4.33E-02	0.00E+00	5.50E-05	2.19E-01	1.10E-01	2.63E-01	9.33E-04	2.22E-03	4.44E-04	7.76E-04	1.14E-02	1.31E-03	2.06E-06	1.20E-05	0.00E+00	1.11E-01	
Beryllium				3.10E-07	1.24E-03	6.18E-04	1.24E-03										6.18E-04	
Cadmium				4.80E-06	1.91E-02	9.57E-03	1.91E-02										9.57E-03	
Chromium				1.10E-05	4.39E-02	2.19E-02	4.39E-02										2.19E-02	
Chromium (VI)																	0.00E+00	
Dichlorobenzene														1.18E-06	6.87E-06	0.00E+00	0.00E+00	
Ethylbenzene	3.20E-05	1.16E-01	0.00E+00				1.16E-01										0.00E+00	
Formaldehyde	1.01E-04	3.63E-01	0.00E+00	2.80E-04	1.12E+00	5.58E-01	1.48E+00	1.18E-03	2.81E-03	5.62E-04	7.89E-05	1.16E-03	1.33E-04	7.35E-05	4.29E-04	0.00E+00	5.59E-01	
Hexane														1.76E-03	1.03E-02	0.00E+00	0.00E+00	
Lead				1.40E-05	5.58E-02	2.79E-02	5.58E-02										2.79E-02	
Manganese				7.90E-04	3.15E+00	1.58E+00	3.15E+00										1.58E+00	
Mercury				1.20E-06	4.79E-03	2.39E-03	4.79E-03										2.39E-03	
Naphthalene	1.30E-06	4.69E-03	0.00E+00	3.50E-05	1.40E-01	6.98E-02	1.44E-01							5.98E-07	3.49E-06	0.00E+00	6.98E-02	
Nickel				4.60E-06	1.83E-02	9.17E-03	1.83E-02										9.17E-03	
PAH	2.20E-06	7.95E-03	0.00E+00	4.00E-05	1.60E-01	7.98E-02	1.67E-01	1.68E-04	4.00E-04	8.00E-05	2.12E-04	3.12E-03	3.58E-04				8.02E-02	
POM														8.65E-08	5.05E-07	0.00E+00	0.00E+00	
Propylene Oxides	2.90E-05	1.05E-01	0.00E+00				1.05E-01										0.00E+00	1.58E+00
Selenium				2.50E-05	9.97E-02	4.99E-02	9.97E-02										4.99E-02	
Toluene	1.30E-04	4.69E-01	0.00E+00				4.69E-01	4.09E-04	9.73E-04	1.95E-04	2.81E-04	4.13E-03	4.75E-04	3.33E-06	1.95E-05	0.00E+00	6.70E-04	
Xylenes	6.40E-05	2.31E-01	0.00E+00				2.31E-01	2.85E-04	6.78E-04	1.36E-04	1.93E-04	2.84E-03	3.26E-04				4.62E-04	
	Total Emissions		**0.00E+00**			**2.57E+00**				**1.84E-03**			**2.66E-03**			**0.00E+00**	**2.57E+00**	

Legend
PTE: Potential to emit
E.F. : Emission factor
CTG: Combustion Turbine Generator

Notes [ ]:
1. Calculation based on CTGs operating at 100 percent base load at ISO conditions (59 F and 60 % Relative Humidity).
2. Emission factors as contained in Table 3.1-3 of AP-42 for natural gas fired stationary gas turbines.
3. Emission factors as contained in Table 3.1-4 and Table 3.1-5 of AP-42 for distillate fuel oil fired turbines.
4. Emission factors as contained in Table 3.3-2 (small engines, < 600 hp) of AP-42 for diesel fired industrial internal combustion engines.
5. Emission factors as contained in Table 3.4-3 (large engines, > 600 hp) of AP-42 for diesel fired industrial internal combustion engines.
6. Emission factors as contained in Table 1.4-3 of AP-42 for external natural gas combustion.
(Combustion Turbine Emissions Database v.5. URL: http://www.epa.gov/ttn/atw/combust/turbine/turbpg.html). The emission factor is an average of the emission factors listed for GE Frame 7F machines at 100% load and is more representative than the formaldehyde emission factor listed in AP-42 Table 3.1-3, which is based on an average emission factor across various types of CTGs.

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Post-Onsite Natural Gas Availability

Table C-13: Emissions Calculations with CTGS firing Natural Gas Only

INPUTS

No. of CTGs
2

Heat Input (MBtu/hr)				
CTG (GAS) [1]	CTG (ULSFO) [1]	Fire Pump	Emergency Engine	Fuel Heater
1805.7	1994.1	2.38	14.70	5.837

Hours of Operation per Unit				
CTG (GAS)	CTG (ULSFO)	Fire Pump	Emergency Engine	Fuel Heater
3500	0	400	230	8760

	Combustion Turbines							Fire Pump			Emergency Diesel Engine Generator			Fuel Heater			
Pollutant	CTG (Natural Gas) Emission factor [2] lb/Mbtu	2 CTGs Natural Gas PTE (lb/hr)	2 CTGs Natural Gas PTE (tpy)	CTG (ULSFO) Emission factor [3] lb/Mbtu	2 CTGs ULSFO PTE (lb/hr)	2 CTGs ULSFO PTE (tpy)	2 CTGs Total NG+ULSFO PTE (lb/hr)	Fire Pump E.F.[4] lb/Mbtu	Fire Pump PTE (lb/hr)	Fire Pump PTE tpy	Emer Eng E.F.[5] lb/Mbtu	Emer Eng PTE (lb/hr)	Emer Eng PTE tpy	Fuel Heater E.F.[6] lb/Mbtu	Fuel Heater PTE (lb/hr)	Fuel Heater PTE tpy	Total PTE tpy
1,3-Butadiene	4.30E-07	1.55E-03	2.72E-03	1.60E-05	6.38E-02	0.00E+00	6.54E-02	3.91E-05	9.31E-05	1.86E-05							2.74E-03
Acetaldehyde	4.00E-05	1.44E-01	2.53E-01				1.44E-01	7.67E-04	1.83E-03	3.65E-04	2.52E-05	3.70E-04	4.26E-05				2.53E-01
Acrolein	6.40E-06	2.31E-02	4.04E-02				2.31E-02	9.25E-05	2.20E-04	4.40E-05	7.88E-06	1.16E-04	1.33E-05				4.05E-02
Arsenic				1.10E-05	4.39E-02	0.00E+00	4.39E-02										0.00E+00
Benzene	1.20E-05	4.33E-02	7.58E-02	5.50E-05	2.19E-01	0.00E+00	2.63E-01	9.33E-04	2.22E-03	4.44E-04	7.76E-04	1.14E-02	1.31E-03	2.06E-06	1.20E-05	5.26E-05	7.76E-02
Beryllium				3.10E-07	1.24E-03	0.00E+00	1.24E-03										0.00E+00
Cadmium				4.80E-06	1.91E-02	0.00E+00	1.91E-02										0.00E+00
Chromium				1.10E-05	4.39E-02	0.00E+00	4.39E-02										0.00E+00
Chromium (VI)																	0.00E+00
Dichlorobenzene														1.18E-06	6.87E-06	3.01E-05	3.01E-05
Ethylbenzene	3.20E-05	1.16E-01	2.02E-01				1.16E-01										2.02E-01
Formaldehyde(7)	1.01E-04	3.63E-01	6.36E-01	2.80E-04	1.12E+00	0.00E+00	1.48E+00	1.18E-03	2.81E-03	5.62E-04	7.89E-05	1.16E-03	1.33E-04	7.35E-05	4.29E-04	1.88E-03	6.38E-01
Hexane														1.76E-03	1.03E-02	4.51E-02	4.51E-02
Lead				1.40E-05	5.58E-02	0.00E+00	5.58E-02										0.00E+00
Manganese				7.90E-04	3.15E+00	0.00E+00	3.15E+00										0.00E+00
Mercury				1.20E-06	4.79E-03	0.00E+00	4.79E-03										0.00E+00
Naphthalene	1.30E-06	4.69E-03	8.22E-03	3.50E-05	1.40E-01	0.00E+00	1.44E-01							5.98E-07	3.49E-06	1.53E-05	8.23E-03
Nickel				4.60E-06	1.83E-02	0.00E+00	1.83E-02										0.00E+00
PAH	2.20E-06	7.95E-03	1.39E-02	4.00E-05	1.60E-01	0.00E+00	1.67E-01	1.68E-04	4.00E-04	8.00E-05	2.12E-04	3.12E-03	3.58E-04				1.43E-02
POM														8.65E-08	5.05E-07	2.21E-06	2.21E-06
Propylene Oxides	2.90E-05	1.05E-01	1.83E-01				1.05E-01										1.83E-01
Selenium				2.50E-05	9.97E-02	0.00E+00	9.97E-02										0.00E+00
Toluene	1.30E-04	4.69E-01	8.22E-01				4.69E-01	4.09E-04	9.73E-04	1.95E-04	2.81E-04	4.13E-03	4.75E-04	3.33E-06	1.95E-05	8.52E-05	8.22E-01
Xylenes	6.40E-05	2.31E-01	4.04E-01				2.31E-01	2.85E-04	6.78E-04	1.36E-04	1.93E-04	2.84E-03	3.26E-04				4.05E-01
	Total Emissions		**2.64E+00**			**0.00E+00**				**1.84E-03**			**2.66E-03**			**4.72E-02**	**2.69E+00**

Legend
PTE: Potential to emit
E.F. : Emission factor
CTG: Combustion Turbine Generator

Notes [ ]:
1. Calculation based on CTGs operating at 100 percent base load at ISO conditions (59 F and 60 % Relative Humidity).
2. Emission factors as contained in Table 3.1-3 of AP-42 for natural gas fired stationary gas turbines.
3. Emission factors as contained in Table 3.1-4 and Table 3.1-5 of AP-42 for distillate fuel oil fired turbines.
4. Emission factors as contained in Table 3.3-2 (small engines, < 600 hp) of AP-42 for diesel fired industrial internal combustion engines.
5. Emission factors as contained in Table 3.4-3 (large engines, > 600 hp) of AP-42 for diesel fired industrial internal combustion engines.
6. Emission factors as contained in Table 1.4-3 of AP-42 for external natural gas combustion.
7. Formaldehyde emission factor for the CTGs firing natural gas was obtained from the USEPA AP-42 Access Database (Combustion Turbine Emissions Database v.5. URL: http://www.epa.gov/ttn/atw/combust/turbine/turbpg.html). The emission factor is an average of the emission factors listed for GE Frame 7F machines at 100% load and is more representative than the formaldehyde emission factor listed in AP-42 Table 3.1-3, which is based on an average emission factor across various types of CTGs.

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Post-Onsite Natural Gas Availability

Table C-14: Emissions Calculations with CTGs Firing Natural Gas and ULSFO

INPUTS

No. of CTGs
2

Heat Input (MBtu/hr)				
CTG (GAS) [1]	CTG (ULSFO) [1]	Fire Pump	Emergency Engine	Fuel Heater
1805.7	1994.1	2.38	14.70	5.837

Hours of Operation per Unit				
CTG (GAS)	CTG (ULSFO)	Fire Pump	Emergency Engine	Fuel Heater
3000	500	400	230	8760

	Combustion Turbines							Fire Pump			Emergency Diesel Engine Generator			Fuel Heater				
Pollutant	CTG (Natural Gas) Emission factor [2] lb/Mbtu	2 CTGs Natural Gas PTE (lb/hr)	2 CTGs Natural Gas PTE (tpy)	CTG (ULSFO) Emission factor [3] lb/Mbtu	2 CTGs ULSFO PTE (lb/hr)	2 CTGs ULSFO PTE (tpy)	2 CTGs Total NG+ULSFO PTE (lb/hr)	Fire Pump E.F.[4] lb/Mbtu	Fire Pump PTE (lb/hr)	Fire Pump PTE tpy	Emer Eng E.F.[5] lb/Mbtu	Emer Eng PTE (lb/hr)	Emer Eng PTE tpy	Fuel Heater E.F.[6] lb/Mbtu	Fuel Heater PTE (lb/hr)	Fuel Heater PTE tpy	Total PTE tpy	
1,3-Butadiene	4.30E-07	1.55E-03	2.33E-03	1.60E-05	6.38E-02	1.60E-02	6.54E-02	3.91E-05	9.31E-05	1.86E-05							1.83E-02	
Acetaldehyde	4.00E-05	1.44E-01	2.17E-01				1.44E-01	7.67E-04	1.83E-03	3.65E-04	2.52E-05	3.70E-04	4.26E-05				2.17E-01	
Acrolein	6.40E-06	2.31E-02	3.47E-02				2.31E-02	9.25E-05	2.20E-04	4.40E-05	7.88E-06	1.16E-04	1.33E-05				3.47E-02	
Arsenic				1.10E-05	4.39E-02	1.10E-02	4.39E-02										1.10E-02	
Benzene	1.20E-05	4.33E-02	6.50E-02	5.50E-05	2.19E-01	5.48E-02	2.63E-01	9.33E-04	2.22E-03	4.44E-04	7.76E-04	1.14E-02	1.31E-03	2.06E-06	1.20E-05	5.26E-05	1.22E-01	
Beryllium				3.10E-07	1.24E-03	3.09E-04	1.24E-03										3.09E-04	
Cadmium				4.80E-06	1.91E-02	4.79E-03	1.91E-02										4.79E-03	
Chromium				1.10E-05	4.39E-02	1.10E-02	4.39E-02										1.10E-02	
Chromium (VI)																	0.00E+00	
Dichlorobenzene														1.18E-06	6.87E-06	3.01E-05	3.01E-05	
Ethylbenzene	3.20E-05	1.16E-01	1.73E-01				1.16E-01										1.73E-01	
Formaldehyde	1.01E-04	3.63E-01	5.45E-01	2.80E-04	1.12E+00	2.79E-01	1.48E+00	1.18E-03	2.81E-03	5.62E-04	7.89E-05	1.16E-03	1.33E-04	7.35E-05	4.29E-04	1.88E-03	8.26E-01	
Hexane														1.76E-03	1.03E-02	4.51E-02	4.51E-02	
Lead				1.40E-05	5.58E-02	1.40E-02	5.58E-02										1.40E-02	
Manganese				7.90E-04	3.15E+00	7.88E-01	3.15E+00										7.88E-01	
Mercury				1.20E-06	4.79E-03	1.20E-03	4.79E-03										1.20E-03	
Naphthalene	1.30E-06	4.69E-03	7.04E-03	3.50E-05	1.40E-01	3.49E-02	1.44E-01							5.98E-07	3.49E-06	1.53E-05	4.20E-02	
Nickel				4.60E-06	1.83E-02	4.59E-03	1.83E-02										4.59E-03	
PAH	2.20E-06	7.95E-03	1.19E-02	4.00E-05	1.60E-01	3.99E-02	1.67E-01	1.68E-04	4.00E-04	8.00E-05	2.12E-04	3.12E-03	3.58E-04				5.22E-02	
POM														8.65E-08	5.05E-07	2.21E-06	2.21E-06	
Propylene Oxides	2.90E-05	1.05E-01	1.57E-01				1.05E-01										1.57E-01	8.26E-01
Selenium				2.50E-05	9.97E-02	2.49E-02	9.97E-02										2.49E-02	
Toluene	1.30E-04	4.69E-01	7.04E-01				4.69E-01	4.09E-04	9.73E-04	1.95E-04	2.81E-04	4.13E-03	4.75E-04	3.33E-06	1.95E-05	8.52E-05	7.05E-01	
Xylenes	6.40E-05	2.31E-01	3.47E-01				2.31E-01	2.85E-04	6.78E-04	1.36E-04	1.93E-04	2.84E-03	3.26E-04				3.47E-01	
	Total Emissions		**2.26E+00**			**1.28E+00**				**1.84E-03**			**2.66E-03**			**4.72E-02**	**3.60E+00**	

Legend

PTE: Potential to emit

E.F. : Emission factor

CTG: Combustion Turbine Generator

Notes [ ]:

1. Calculation based on CTGs operating at 100 percent base load at ISO conditions (59 F and 60 % Relative Humidity).
2. Emission factors as contained in Table 3.1-3 of AP-42 for natural gas fired stationary gas turbines.
3. Emission factors as contained in Table 3.1-4 and Table 3.1-5 of AP-42 for distillate fuel oil fired turbines.
4. Emission factors as contained in Table 3.3-2 (small engines, < 600 hp) of AP-42 for diesel fired industrial internal combustion engines.
5. Emission factors as contained in Table 3.4-3 (large engines, > 600 hp) of AP-42 for diesel fired industrial internal combustion engines.
6. Emission factors as contained in Table 1.4-3 of AP-42 for external natural gas combustion.
7. Formaldehyde emission factor for the CTGs firing natural gas was obtained from the USEPA AP-42 Access Database (Combustion Turbine Emissions Database v.5, URL: http://www.epa.gov/ttn/atw/combust/turbine/turbpg.html). The emission factor is an average of the emission factors listed for GE Frame 7F machines at 100% load and is more representative than the formaldehyde emission factor listed in AP-42 Table 3.1-3, which is based on an average emission factor across various types of

Natural Gas

Emission Factor Report for Formaldehyde with All Lean Premix *03-Apr-08*

ID	Manufacturer	Model	Rating (MW)	Load (%)	EF (lb/MMBtu)		Count of Runs	ND Count	Control Device
27	General Electric	Frame 6	42.5	100	<	5.72E-05	3	1	DLN unit; also SCR and ammonia injection
324.2.1	General Electric	Frame 7F	165	100		3.04E-05	3	0	Lean Premix and SCR
324.1.1	General Electric	Frame 7F	165	100		2.16E-05	3	0	Lean Premix and SCR
321.4	General Electric	Frame 7F	130	100		9.78E-05	3	0	Lean Premix
320.3	General Electric	Frame 7F	130	100		2.43E-04	3	0	Lean Premix
319.2	General Electric	Frame 7F	130	100		1.10E-04	3	0	Lean Premix (Dry Low NOx)
314.3	Solar	Mars SoL	10.9	50		5.85E-04	3	0	Lean pre-mix (SoLoNOx)

ID	Manufacturer	Model	Rating (MW)	Load (%)	EF (lb/MMBtu)	Count of Runs	ND Count	Control Device
314.2	Solar	Mars SoL	10.9	75	4.93E-05	3	0	Lean pre-mix (SoLoNOx)
314.1	Solar	Mars SoL	10.9	100	1.45E-05	3	0	Lean pre-mix (SoLoNOx)

Avg EF = 1.34E-04

Count = 9

TANKS 4.0.9d
Emissions Report - Summary Format
Tank Identification and Physical Characteristics

Identification

User Identification:	JEA Tank-1
City:	Jacksonville
State:	Florida
Company:	JEA
Type of Tank:	Vertical Fixed Roof Tank
Description:	JEA GEC ULSFO Tanks (Identical 1 and 2 Tanks)

Tank Dimensions

Shell Height (ft):	35.00
Diameter (ft):	100.00
Liquid Height (ft) :	29.00
Avg. Liquid Height (ft):	29.00
Volume (gallons):	1,703,809.66
Turnovers:	8.86
Net Throughput(gal/yr):	15,100,000.00
Is Tank Heated (y/n):	N

Paint Characteristics

Shell Color/Shade:	White/White
Shell Condition	Good
Roof Color/Shade:	White/White
Roof Condition:	Good

Roof Characteristics

Type:	Dome
Height (ft)	13.40
Radius (ft) (Dome Roof)	100.00

Breather Vent Settings

Vacuum Settings (psig):	-0.03
Pressure Settings (psig)	0.03

Meterological Data used in Emissions Calculations: Jacksonville, Florida (Avg Atmospheric Pressure = 14.75 psia)

TANKS 4.0.9d
Emissions Report - Summary Format
Liquid Contents of Storage Tank

JEA Tank-1 - Vertical Fixed Roof Tank
Jacksonville, Florida

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis fc Calcula
Distillate fuel oil no. 2	*All*	*69.96*	*64.29*	*75.63*	*68.02*	*0.0090*	*0.0076*	*0.0107*	*130.0000*			*188.00*	*Option*

TANKS 4.0.9d
Emissions Report - Summary Format
Individual Tank Emission Totals

Emissions Report for: Annual

JEA Tank-1 - Vertical Fixed Roof Tank
Jacksonville, Florida

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Distillate fuel oil no. 2	420.18	293.47	713.65

Appendix D
BACT Analysis

Best Available Control Technology Analysis
for
JEA – Greenland Energy Center
Units 1 and 2
Simple Cycle Combustion Turbines

Submitted by

JEA

April 2008
Project No. 148570

BLACK & VEATCH
Building a world of difference.

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1.0 Introduction and Executive Summary

JEA proposes to construct a new electric generating facility (hereinafter referred to as the "Project") at its new Greenland Energy Center (GEC) in Jacksonville, Florida. The Project will consist of two (2) simple cycle combustion turbines (SCCT), emergency diesel engine, emergency diesel fire pump, and a fuel gas heater. This document presents the BACT analysis and emissions control conclusions for the Project.

Table 1-1 lists a summary of the proposed BACT determinations and associated emission rates for two (2) GE Model PG7241 (FA) Combustion Turbine Generators (CTG) operating in simple cycle mode (GEC Unit 1 and Unit 2). GEC Unit 1 and Unit 2 will fire natural gas and/or ultra-low sulfur fuel oil (ULSFO) with 0.0015 percent sulfur by weight. The operational modes for GEC are discussed in detail in Section 2.2.6. For the purposes of the BACT analysis, two operating scenarios are considered for evaluation of controls:

- Pre-onsite natural gas availability: GEC Unit 1 and Unit 2 firing exclusively ULSFO for 1,000 hours per unit per year.
- Post-onsite natural gas availability: GEC Unit 1 and Unit 2 firing natural gas for 3,000 hours per unit per year and ULSFO for 500 hours per unit per year.

It should be noted that the emissions for the BACT analysis are based on 100 percent load conditions at ambient air temperature of 59° F and 60 percent relative humidity (60% RH) (hereinafter referred to as ISO conditions).

In accordance with the pre-application meeting between JEA and Florida Department of Environmental Protection (FDEP), it was agreed to base the Project's BACT applicability on the potential to emit (PTE) of the combined cycle build out. Therefore, as presented in Section 2 of the Air Permit Technical Support Document, the SCCT Project is subject to BACT review for the following pollutants: nitrogen oxides (NO_x), sulfur dioxides (SO_x), carbon monoxide (CO), particulate matter/particulate matter less than ten microns (PM/PM_{10}), and sulfuric acid mist (H_2SO_4).

As is required under the NSR/PSD regulations, the following BACT analysis employs a "top-down," five-step analysis process to determine the appropriate emission control technologies and emissions limitations for the Project. The BACT analysis was conducted for GEC Unit 1 and Unit 2, emergency diesel engine generator, diesel engine driven fire pump, and natural gas heater. The BACT analysis was conducted in accordance with the United States Environmental Protection Agency's (USEPA's) recommended methodology:

- Step 1--Identify All Control Technologies.
- Step 2--Eliminate Technically Infeasible Options.
- Step 3--Rank Remaining Control Technologies by Control Effectiveness.

- Step 4--Evaluate Most Effective Controls.
- Step 5--Select BACT.

Step 1--Identify All Control Technologies

The first step in a "top-down" analysis is to identify all available control options for the emission unit in question. Identifying all the potential available control options consists of those air pollution control technologies or techniques with a practical potential for application to the emission unit and the regulated pollutant under evaluation. The potential available control technologies and techniques include lower emitting processes, practices, and post-combustion controls. Lower emitting practices can include fuel cleaning, treatment, or innovative fuel combustion techniques that are classified as pre-combustion controls. Post-combustion controls would be the various add-on controls for the pollutant being controlled.

Step 2--Eliminate Technically Infeasible Options

The second step of the "top-down" analysis is to identify the technical feasibility of the control options identified in Step 1, which are evaluated with respect to source-specific factors. A control option that is determined to be technically infeasible is eliminated. "Technically infeasible" is defined as a clearly documented case of a control option that has technical difficulties that would preclude the successful use of the control option because of physical, chemical, and engineering principles. After completion of this step, technically infeasible options are then eliminated from the BACT review process.

In Step 2, the control option is identified as technically feasible. A "technically feasible" control option is defined as a control technology that has been installed and operated successfully at a similar type of source of comparable size under review (demonstrated). If the control option cannot be demonstrated, the analysis gets more involved. When determining if a control option has not been demonstrated, two key concepts need to be analyzed. The first concept, availability, is defined as technology that can be obtained through commercial channels or is otherwise available within the common sense meaning of the term. A technology that is being offered commercially by vendors or is in licensing and commercial demonstration is deemed an available technology. Technologies that are in development (concept stage/research and patenting) and testing stages (bench-scale/laboratory testing/pilot scale testing) are classified as not available. The second concept, "applicability," is defined as an available control option that can reasonably be installed and operated on the source type under consideration. In summary, the commercially available technology is applicable if it has been previously installed and operated at a similar type of source of comparable size, or a source with similar gas stream characteristics.

Step 3--Rank Remaining Control Technologies by Control Effectiveness

The third step of the "top-down" analysis is to rank all the remaining control alternatives not eliminated in Step 2, based on control effectiveness for the pollutant under review. If the BACT analysis proposes the top control alternative, there would be no need to provide cost and other detailed information in regard to other control options that would provide less control.

Step 4--Evaluate Most Effective Controls

Once the control effectiveness is established in Step 3 for all the feasible control technologies identified in Step 2, additional evaluations of each technology are performed to make a BACT determination in Step 4. The impacts of the technology implementation on the viability of the control technology at the source are evaluated. The evaluation process of these impacts is also known as "Impact Analysis." The following impact analyses are performed:

- Energy evaluation of alternatives.
- Environmental evaluation of alternatives.
- Economic evaluation of alternatives.

The first impact analysis addresses the energy evaluation of alternatives. The energy impact of each evaluated control technology is the energy penalty or benefit resulting from the operation of the control technology at the source. Direct energy impacts include such items as the auxiliary power consumption of the control technology and the additional draft system power consumption to overcome the additional system resistance of the control technology in the flue gas flow path. The costs of these energy impacts are defined either in additional fuel costs or the cost of lost generation, which impacts the cost-effectiveness of the control technology.

The second impact analysis addresses the environmental evaluation of alternatives. Non-air quality environmental impacts are evaluated to determine the cost to mitigate the environmental impacts caused by the operation of a control technology. Examples of non-air quality environmental impacts include polluted water discharge and solids or waste generation. The procedure for conducting this analysis should be based on a consideration of site-specific circumstances.

The third and final impact analysis addresses the economic evaluation of alternatives. This analysis is performed to indicate the cost to purchase and operate the control technology. The capital and operating/annual cost is estimated based on the established design parameters. Information for the design parameters should be obtained from established sources that can be referenced. However, documented assumptions can be made in the absence of references for the design parameters. The estimated cost of control is represented as an annualized cost ($/year) and, with the estimated quantity of pollutant removed (tons/year), the cost-effectiveness ($/tons) of the control technology is determined. The cost-effectiveness describes the potential to achieve the required emissions reduction in the most economical way. The cost-effectiveness compares the potential technologies on an economical basis. Two types of cost-effectiveness are considered in a BACT analysis: average and incremental cost-effectiveness. Average cost-effectiveness is defined as the total annualized cost of control divided by the annual quantity of pollutant removed for each control technology. The incremental cost-effectiveness is a comparison of the cost and performance level of a control technology to the next most stringent option. It has a unit of (dollars/incremental ton removed). The incremental cost-effectiveness is a good measure of viability when comparing technologies that have similar removal efficiencies.

Step 5--Select BACT

The highest ranked control technology that is not eliminated in Step 4 is proposed as BACT for the pollutant and emission unit under review.

Table 1-1 summarizes the BACT analysis process results by identifying the proposed control technology and emissions level determinations for the Project's affected air emissions sources and pollutants.

Table 1-1
BACT Determination Summary

Emission Unit: Nominal 352 MW SCCT Unit 1 and 2 (F-Class PG7241FA)				
Pollutant	**Control Technology**	**Emission Basis**	**Compliance Method**	**CEMS Avg. Period**
NO_x	DLN (for natural gas combustion) / WI (for ULSFO combustion)	Natural Gas: 9.0 ppmvd @ 15% O_2 ULSFO: 42.0 ppmvd @ 15% O_2	Stack Test, 3-Run Avg.	24-hr block
CO	Good Combustion Controls	Natural Gas: 4.1 ppmvd @ 15% O_2 ULSFO: 8.0 ppmvd @ 15% O_2	Stack Test, 3-Run Avg.	24-hr block
PM/PM_{10}	Natural Gas (2.0 gr S/100 SCF) ULSFO (0.0015% S) Good Combustion Practices	10% Opacity	USEPA Method 9 Fuel Sulfur Records	NA
SO2	Natural Gas (2.0 gr S/100 SCF) ULSFO (0.0015% S)	NA	Fuel Sulfur Records	NA
H_2SO_4	Natural Gas (2.0 gr S/100 SCF) ULSFO (0.0015% S)	NA	Fuel Sulfur Records	NA

Emission Unit: Emergency Diesel Engine Generator (1,500 kW)	
Pollutant	**Control Technology**
SO_2	ULSFO
NO_x	Good Combustion Controls
PM/PM_{10}	ULSFO
CO	Good Combustion Controls
H_2SO_4	ULSFO

Emission Unit: Emergency Diesel Fire Pump (350 bhp)	
Pollutant	**Control Technology**
SO_2	ULSFO
NO_x	Good Combustion Controls
PM/PM_{10}	ULSFO
CO	Good Combustion Controls
H_2SO_4	ULSFO

Table 1-1 (Continued)
BACT Determination Summary

Fuel Gas Heater (5.84 MBtu/hr)	
Pollutant	**Control Technology**
SO_2	Natural Gas Firing
NO_x	Good Combustion Controls
PM/PM_{10}	Natural Gas Firing
CO	Good Combustion Controls
H_2SO_4	Natural Gas Firing

CEMS = Continuous Emissions Monitoring System.
MBtu = Million British Thermal Unit.
SCR = Selective Catalytic Reduction.

2.0 BACT Analysis Basis

This section describes the basis of the GEC BACT analysis. Information is provided on the BACT methodology and approach used as well as the parameters and factors used in developing the analysis. The BACT analysis for GEC Unit 1 and Unit 2 are based on certain regulatory requirements and project assumptions. The following is a summary of the requirements and assumptions for which this BACT analysis is based.

2.1 Regulatory Basis

The Clean Air Act Amendments of 1990 (CAA) established revised conditions for the approval of pre-construction permit applications under the PSD program. One of these requirements is that BACT be installed to control all pollutants regulated under the Act that are emitted in significant amounts from new major sources or major modifications.

The applicable state regulations governing this process define BACT in Rule 62-210.200(37), F.A.C. as:

> *"Best Available Control Technology" or "BACT" – An emission limitation, including a visible emissions standard, based on the maximum degree of reduction of each pollutant emitted which the Department, on a case by case basis, taking into account energy, environmental and economic impacts, and other costs, determines is achievable through application of production processes, and available methods, systems and techniques (including fuel cleaning or treatment or innovative fuel combustion techniques) for control of each such pollutant."*

However, BACT cannot be less stringent than the emissions limits established by an applicable New Source Performance Standard (NSPS). These limits are given in NSPS Subpart KKKK.

To bring consistency to the BACT process, the USEPA provides as guidance to the states the use of a "top-down" approach to BACT determinations, which utilizes the five-step analysis process previously summarized. In practice, the top-down BACT analysis determines the most stringent control technology and emissions limitation combination available for a similar source or source category of emission units. At the head of the list in the top-down analysis methodology are the control technologies and emissions limits that represent the Lowest Achievable Emission Rate (LAER) determinations, which, under NSR/PSD regulations, represent the most effective control alternative that must be considered under the BACT analysis process.

The following informational databases, clearinghouses, and documents were used to identify recent control technology determinations for similar source categories and emission units for this BACT analysis:

- USEPA's RACT/BACT/LAER Clearinghouse (RBLC).
- USEPA's National Combustion Turbine Projects Spreadsheet.
- Federal/State/Local new source review permits, permit applications, and associated inspection/test reports.
- Technical journals, newsletters, and reports.
- Information from air quality control (AQC) technology suppliers.
- Engineering design on other projects.

If it cannot be shown that the top level of control is infeasible (for a similar type source and fuel category) on the basis of technical, economic, energy, or environmental impact considerations, then that level of control must be declared to represent BACT for the respective pollutant and air emissions source. Alternatively, upon proper documentation that the top level of control is not feasible for a specific unit and pollutant based on a site- and project-specific consideration of the aforementioned screening criteria (e.g., technical, economic, energy, and environmental considerations), then the next most stringent level of control is identified and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any technical, economic, energy, or environmental consideration. BACT cannot be determined to be less stringent than the emissions limits established by an applicable New Source Performance Standard (NSPS) for the affected air emissions source.

2.1.1 Applicable NSPS Emissions Limits

As previously discussed, a proposed BACT emissions limit, established in accordance with the top-down, five-step process, cannot be determined to be less stringent than the emissions limit(s) established by the applicable NSPS regulations found in 40 CFR Part 60. The following NSPS emissions limitations are applicable to the Project's air emissions sources.

2.1.1.1 NSPS Subpart KKKK – Standards of Performance for Stationary Combustion Turbines. As new stationary SCCTs, Units 1 and 2 will be subject to NSPS Subpart KKKK. Additionally, because the Project is subject to Subpart KKKK, it is not subject to Subpart GG. Applicable NSPS Subpart KKKK emissions limitations for the Project are as follows:

- NO_x--15 ppm at 15 percent O_2 or 54 ng/J of useful output (0.43 lb/MWh) – new turbines firing natural gas with > 850 MBtu/hr heat input.

- NO_x--42 ppm at 15 percent O_2 or 160 ng/J of useful output (1.3 lb/MWh) – new turbines firing fuel oil with > 850 MBtu/hr heat input.
- NO_x--96 ppm at 15 percent O_2 or 590 ng/J of useful output (4.7 lb/MWh) – turbines operating at less than 75 percent of peak load – turbines with > 30 MW output.
- SO_2--The rule includes a fuel emission standard or a fuel sulfur standard equivalent to potential SO_2 emissions of 0.060 lb SO_2/MBtu.

2.1.1.2 NSPS Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines. The Project's emergency diesel engine generator and emergency diesel fire pump will be subject to the manufacturer's certification requirements of compliance to NSPS Subpart IIII. The rule provides various emissions standards based on the engine's use, manufacture date, and engine size. The applicable standards associated with the equipment will be dependent on the engine model year.

Beginning with engines manufactured in model year 2007, the onus of this rule falls on the engine manufacturers, since they are required to manufacture engines that comply with the rule. The requirement of this rule for owners and operators of these engines is that they purchase certified engines.

2.2 Unit Operations and Baseline Emissions Basis

The following sections present the operating and emissions baseline basis for the Project.

2.2.1 GEC Unit 1 and Unit 2

Table 2-1 presents the BACT design basis for each CTG. Table 2-2 shows the baseline emission rates for each CTG at 100 percent base load at the ISO inlet air temperature of 59° F for natural gas and ULSFO. The emissions shown in Table 2-2 are based on the use of dry low NO_x burners during natural gas firing and the use of water injection during ULSFO firing. The lb/MBtu values are based on the higher heating value (HHV) of the expected fuels to be fired. Table 2-3 shows the baseline emissions for GEC Unit 1 and Unit 2 based on a limited number of hours of firing natural gas or ULSFO for the BACT analysis.

Table 2-1
Combustion Turbine BACT Design Basis[1]

Size	Nominal 352 MW (176 MW per SCCT)[1] Nominal 380 MW (190 MW per SCCT)[2]
Combustion Turbine Generator (CTG)	
Maximum Heat Input	1,806 MBtu/h[1]
Maximum Heat Input	1,994 MBtu/h[2]
Operating Hours	Dependant on which fuel is consumed[3]
Fuel	Natural Gas or Ultra-Low Sulfur Fuel Oil (ULSFO) with 0.0015 percent sulfur by weight
Startup Fuel	Natural Gas or ULSFO with 0.0015 percent sulfur by weight

[1]Based on the HHV when firing Natural Gas at ISO conditions.
[2]Based on the HHV when firing ULSFO at ISO conditions.
[3]Please refer to Section 2.2.6 Mode of Operation in the Application Support Document, for details on the fuel usage scenarios. Section 1.0 of this Appendix also presents the operational scenarios considered for the evaluation of controls.

Table 2-2
Emission Rates for Each CTG

Emission Parameter	Natural Gas Firing[a]	ULSFO Firing[b]
NO_x, ppmvd at 15% O_2	9.0	42.0
NO_x, lb/h	58.5	329.4
NO_x, lb/Mbtu (HHV)	0.0324	0.1652
CO, ppmvd at 15% O_2	4.1	8.0
CO, lb/h	16.2	38.2
CO, lb/Mbtu (HHV)	0.009	0.0192
PM/PM_{10} (front and back), lb/h[c]	18	34
PM/PM_{10} (front and back), lb/Mbtu (HHV)[c]	0.0100	0.0171
SO_2, lb/h[d]	8.23	2.45
SO_2, lb/Mbtu (HHV)[d]	0.0046	0.0012
H_2SO_4, lb/h[e]	3.15	0.94
H_2SO_4, lb/Mbtu[e]	0.0017	0.00047

[a]Emissions are based on firing natural gas at 100 percent of base load at ISO conditions.
[b]Emissions are based on firing ULSFO at 100 percent of base load at ISO conditions.
[c]PM/PM_{10} without the effects of SO_2 oxidation.
Based on a natural gas sulfur content of 2 grains/100 scf, and the use of ULSFO with 0.0015 percent sulfur content.
[e]H_2SO_4 value assumes a 20 percent molar conversion rate of SO_2 to SO_3 in the CT with a 100% conversion from SO_3 to H_2SO_4.

Table 2-3
GEC Unit 1 and Unit 2 Baseline Uncontrolled Emissions
(per CT)

Emission Parameter	ULSFO Firing[a]	Natural Gas + ULSFO Firing
NO_x, tons per year (tpy)	164.7	170.1[b]
CO, tpy	19.1	33.9[b]
PM/PM_{10} (front and back), tpy	17.0	35.5[b]
SO_2, tpy	1.2	14.4[c]
H_2SO_4, tpy	0.5	5.5[c]

[a] This is the pre-onsite natural gas availability scenario. Emissions are based on GEC Unit 1 and Unit 2 operating 1,000 hours per unit per year on ULSFO at 100 percent of base load with no evaporative cooling at ISO conditions.

[b] This is the post-onsite natural gas availability scenario. Emissions are based on GEC Unit 1 and Unit 2 operating 3,000 hours per unit per year on natural gas and 500 hours per unit per year on ULSFO, at 100 percent of base load with no evaporative cooling at ISO conditions, respectively.

[c] This is the post-onsite natural gas availability scenario. Emissions are based on GEC Unit 1 and Unit 2 operating 3,500 hours per unit per year on natural gas, at 100 percent of base load with no evaporative cooling at ISO conditions, respectively.

2.3 Economic Basis

The economic analyses used to determine the capital and annualized costs of the control technologies were based on USEPA methodologies shown in the USEPA "Best Available Control Technology Draft Guidance Document" (October 1990), "Top Down" Best Available Control Technology Guidance Document" (March 1990), The Office of Air Quality Planning and Standards (OAQPS) *Control Cost Manual* (February 1996, Fifth Edition), internal owner cost factors, and vendor budgetary cost quotes.

Table 2-4 lists the economic criteria used in the analysis of BACT alternatives. The capital recovery factor was calculated based on the present worth discount rate and economic life of the equipment or the assumed catalyst life.

Table 2-4
Project Economic Evaluation Criteria

Economic Parameters	Value
Contingency, percent	10
Escalation, percent	2.5
Present Worth Discount Rate, percent	5.0
Economic Life, years	20
Capital Recovery Factor, (20 years)	0.0802
SCR Catalyst Life, years	3
$SCONO_x$ Catalyst Life, years	5
CO Catalyst Life, years	3
Catalyst Capital Recovery Factor (3 years)	0.3672
$SCONO_x$ Catalyst Capital Recovery Factor (5 years)	0.2310
Labor Cost, $/man-hour (2008)	53
Natural Gas Cost, $/MBtu (2008)	8.10
19% Aqueous Ammonia Cost, $/ton (2008)	195
Energy Cost, $/kWh (2008)	0.063
Sales Tax, percent	N/A

3.0 GEC Unit 1 and Unit 2 NO_x and CO BACT Analysis

This section presents the top-down, five-step BACT process used to evaluate and determine the Project's NO_x and CO emissions limits for GEC Unit 1 and Unit 2. As this analysis will demonstrate, the proposed NO_x BACT limit for Unit 1 and Unit 2 is an emission limit of 9.0 ppmvd at 15 percent O_2 while firing natural gas and 42.0 ppmvd at 15 percent O_2 while firing ULSFO. The proposed CO BACT limit for Unit 1 and Unit 2 is an emissions limit of 4.1 ppmvd at 15 percent O_2 while firing natural gas and 8.0 ppmvd at 15 percent O_2 while firing ULSFO.

3.1 Step 1--Identify All NO_x Control Technologies

The first step in a top-down analysis, according to the EPA's October 1990, Draft New Source Review Workshop Manual, is to identify all available control options. Available control options are those air pollution control technologies or techniques with a practical potential for application to the emission unit and the NO_x emissions limit that is being evaluated.

NO_x is defined as the combination of nitrogen oxide (NO) and nitrogen dioxide (NO_2). NO_x emissions formed through the oxidation of the fuel bound nitrogen are called fuel NO_x. NO_x emissions formed through the oxidation of a portion of the nitrogen contained in the combustion air are called thermal NO_x and are a function of combustion temperature. NO_x production in a gas turbine combustor occurs predominantly within the flame zone, where localized high temperatures sustain the NO_x-forming reactions. The overall average gas temperature required to drive the turbine is well below the flame temperature, but the flame region is required to achieve stable combustion.

Nitrogen oxide control methods may be divided into two categories: in-combustor NO_x formation control and post-combustion emission reduction. An in-combustor NO_x formation control process reduces the quantity of NO_x formed in the combustion process. A post-combustion technology reduces the NO_x emissions in the flue gas stream after the NO_x has been formed in the combustion process. Both of these methods may be used alone or in combination to achieve the various degrees of NO_x emissions required. The six different types of emission controls reviewed by this BACT analysis are as noted below.

- In-Combustor Type:
  - Water/Steam Injection
  - Dry Low-NO_x (DLN) Burners
  - Xonon

- Post-Combustion Type:
  - Selective Non-Catalytic Reduction (SNCR)
  - $SCONO_x$ with Dilution Air System
  - Selective Catalytic Reduction (SCR) with Dilution Air System
  - High-Temperature SCR

The rationale behind whether the above technologies are evaluated as NO_x control for BACT is included in the following subsections.

3.1.1 Water or Steam Injection

NO_x emissions from GEC Unit 1 and Unit 2 can be controlled by either water or steam injection. This type of control injects water or steam into the primary combustion zone with the fuel. The water or steam serves to reduce NO_x formation by reducing the peak flame temperature. The degree of reduction in NO_x formation is proportional to the amount of water injected into the combustion turbine. A limit exists, however, on the amount of water that can be injected into the system before reliability of the combustion turbine is seriously degraded and operational life is affected. This type of control can also be counterproductive with regard to CO and VOC emissions that are formed as a result of incomplete combustion.

3.1.2 Dry Low-NO_x Burners

NO_x formation can be limited by lowering combustion temperatures and by staging combustion (i.e., creating a reducing atmosphere followed by an oxidizing atmosphere). The use of dry low-NO_x (DLN) burners as a way to reduce flame temperature is one common NO_x control method. These combustor designs are called DLN burners because, when firing natural gas, injecting water into the combustion chamber is not necessary to achieve low NO_x emissions. Most industry gas turbine manufacturers today have developed this type of lean premix combustion system as the state of the art for NO_x controls in combustion turbines. This method is exclusively utilized when firing natural gas.

3.1.3 XONON

Another form of in-combustor control is XONON. This technology, developed by Catalytica Combustion Systems, is designed to avoid the high temperatures created in conventional combustors. The XONON combustor operates below 2,700° F at full power generation, which significantly reduces NO_x emissions without raising, and possibly even lowering, emissions of CO and unburned hydrocarbons. XONON uses a proprietary flameless process in which fuel and air react on the surface of a catalyst in the turbine combustor to produce energy in the form of hot gases, which drive the turbine.

This emerging technology is being commercialized by several joint ventures that Catalytica has with turbine manufacturers.

3.1.4 Selective Non-Catalytic Reduction

Selective non-catalytic reduction (SNCR) is one method of post-combustion control. SNCR selectively reduces NO_x into nitrogen and water vapor by reacting the flue gas with a reagent. SNCR systems can use either ammonia (Thermal $DeNO_x$) or urea (NO_xOUT) as reagents.

The SNCR system is dependent upon the reagent injector location and temperature to achieve proper reagent/flue gas mixing for maximum NO_x reduction. SNCR systems require a fairly narrow temperature range for reagent injection in order to achieve a specific NO_x reduction efficiency. The optimum temperature range for injection of ammonia or urea is 1,550° to 1,900° F. The NO_x reduction efficiency of an SNCR system decreases rapidly at temperatures outside the optimum temperature window. Injection of reagent below this temperature window results in excessive ammonia emissions (ammonia slip). Injection of reagent above the temperature window results in increased NO_x emissions.

The exhaust temperatures at the exit of GEC Unit 1 and Unit 2 are between 1040° to 1200° F. Therefore, the exhaust temperature is less than the optimum temperature range for the application of this technology. It is not technically feasible to apply this technology to this Project and it will be eliminated from further evaluation in this BACT analysis.

3.1.5 $SCONO_x$ with Dilution Air System

A second, post-combustion technology from EmeraChem, LLC is EM_X™ ($SCONO_x$), which utilizes a coated oxidation catalyst to remove both NO_x and CO without a reagent such as ammonia. EmeraChem purchased $SCONO_x$ from Goal Line Environmental Technologies and ABB Alstom Power.

The $SCONO_x$ system utilizes hydrogen (H_2) (which is created by reforming natural gas) as the basis for a proprietary catalyst regeneration process. The system consists of a platinum-based catalyst coated with potassium carbonate (K_2CO_3) to oxidize both NO_x and CO, thereby reducing total plant emissions. CO emissions are decreased by the oxidation of CO to carbon dioxide (CO_2). The catalyst is installed in the flue gas at a point where the temperature is between 300° to 700° F. As indicated above, GEC Unit 1 and Unit 2 would require dilution air systems to be installed in order to maintain flue gas temperatures below the upper temperature range of 700° F. Dilution air systems are blower packages and air distribution piping that allow ambient air to be injected in the CT outlet to lower the CT outlet exhaust temperature.

EmeraChem guarantees the performance of the catalyst for 3 years. When the catalyst reaches the end of its service life, it can be recycled to recover the precious metal contained within the catalyst.

The $SCONO_x$ catalyst is very susceptible to fouling by sulfur in the flue gas. The impact of sulfur can be minimized by a sulfur absorption $SCOSO_x$ catalyst. The $SCOSO_x$ catalyst is located upstream of the $SCONO_x$ catalyst. The SO_2 is oxidized to sulfur trioxide (SO_3) by the $SCOSO_x$ catalyst. The SO_3 is then deposited on the catalyst and removed from the catalyst when it is regenerated. The $SCOSO_x$ catalyst is regenerated along with the $SCONO_x$ catalyst.

The $SCONO_x$ catalyst will require that it be re-coated 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 $SCOSO_x$ 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 $SCOSO_x$ catalyst will also require washing, but due to limited operating experience with the $SCOSO_x$ catalyst, it is uncertain how often this will be required. However, it is expected that the $SCOSO_x$ catalyst will require annual washing.

The current $SCONO_x$ catalyst technology is in its second generation. The first generation operated for approximately 10 months on a small LM-2500 combined cycle combustion turbine unit before the $SCONO_x$ system was taken out of service because of poor regeneration gas distribution.

The USEPA has stated its concerns (November 19, 1999 letter from USEPA Region I) with the technical uncertainties of the $SCONO_x$ system and expressed apprehensive about applying $SCONO_x$ technology to large combined cycle turbines that burn primarily natural gas. The technical uncertainties noted for the scale-up of the $SCONO_x$ system include the following:

- The dampers must be significantly larger in its cross-sectional area compared to the much smaller turbines in service with the $SCONO_x$ systems. A good seal to isolate the catalyst from the flue gas to limit ambient oxygen concentrations and for safety of personnel working with catalyst replacement.
- The removal and replacement of the catalyst for re-coating without adversely impacting unit availability.
- The superstructure that will be needed to handle the catalyst during replacement.
- Ensuring there is proper distribution to the regeneration gas.

- The operating range of the $SCONO_x$ systems currently operating are less than 45 MW. (e.g. The Redding Electric Municipal Power Plant in Redding, California, utilizes a $SCONO_x$ system for a 45 MW gas turbine).

GEC Units 1 and 2 are simple cycle combustion turbines, however, with the dilution air systems added to limit the flue gas temperature to less than 700°F, the flue gas characteristics become similar to that of a combined cycle turbine.

While the $SCONO_x$ technology may have future promise, the application of this technology is currently limited to natural gas combined cycle combustion turbine units under 45 MW. Although the technology is not considered feasible for this application, SCONOx will be evaluated in the BACT for NO_x control to ensure the provision of a complete technology analysis.

3.1.6 Selective Catalytic Reduction with Dilution Air System

Another post-combustion method of NO_x control is selective catalytic reduction (SCR). SCR systems have been used quite extensively on combined cycle projects for the past ten years. The SCR process combines vaporized ammonia with NO_x in the presence of a catalyst to form nitrogen and water. The vaporized ammonia is injected into the combustion turbine exhaust gases prior to passage through the catalyst bed. The use of SCR results in small levels of ammonia emissions (ammonia slip). As the catalyst degrades ammonia slip will increase to approximately 5 -10 ppmvd (dependent on system design), ultimately requiring catalyst replacement.

The performance and effectiveness of SCR systems are directly dependent on the temperature of the flue gas when it passes through the catalyst. Vanadium/titanium catalysts have been used on the majority of SCR system installations. The flue gas temperature range for optimum SCR operation using a conventional vanadium/titanium catalyst is approximately 600 to 750° F. At temperatures above 850° F permanent damage to the vanadium/titanium catalyst occurs. As indicated earlier, GEC Unit 1 and Unit 2 are assumed to have dilution air systems installed in order to accommodate the upper temperature range of 600 to 750° F. Accordingly, a vanadium/ titanium catalyst can be installed for GEC Unit 1 and Unit 2 with a dilution air system. Therefore, the vanadium/titanium-based catalyst will be evaluated further for these units.

Because the SCR system requires the regulation of ammonia injection based on the NO_x emission monitors, the accuracy of the emission reading directly influences the amount of actual error in the ammonia injection rate. Therefore, erroneous emission readings can result in excess ammonia levels even when the actual NO_x value is below the permitted value. This may result in excessive ammonia "slip" being discharged to the atmosphere with little or no improvement in NO_x emissions. Reduction of the NO_x emission concentrations to levels below 2.0 ppmvd while firing natural gas and below 8.0

ppmvd while firing ULSFO also raises concerns with the additional ammonia that may be emitted to obtain further reduced levels. Although SCR catalyst vendors have indicated that ammonia emissions will not be increased, these vendors are not solely responsible for guaranteeing ammonia slip and only provide guarantees for stable load conditions. The distribution of the ammonia in the duct is the key parameter since localized maldistribution of the ammonia will cause the ammonia to pass through the catalyst without reacting with the NO_x. The proper distribution of the gas and ammonia is difficult to obtain when both reactants, NO_x and NH_3, are at such low concentrations. This distribution would be even more difficult, if not impossible, to maintain during transient operations, such as load changes, when flow patterns are changing. Changes in operation from one stable load to another stable load may present problems since the flow patterns and the loads may be different. Since the catalyst vendors are not responsible for the ammonia distribution, they typically limit their guarantees to some distribution level.

This SCR method of post-combustion control will be considered further in this BACT analysis to control NO_x emissions.

3.1.7 High-Temperature Selective Catalytic Reduction

A high temperature catalyst vendor, Haldor-Topsoe, provided comments on the disadvantages of using high-temperature catalysts versus low-temperature catalysts. Haldor-Topsoe stated that an SCR NO_x control system would require more catalyst volume for a high-temperature catalyst application. As the catalyst volume is increased, the following become items of concern:

- The pressure drop across the catalyst increases (unless the ductwork is expanded).
- Oxidation of ammonia occurs at high-temperature environments (1,000° F+), which creates more free nitric oxide.
- More ammonia consumption occurs due to the increase in free nitric oxide.
- More SO_2 to SO_3 conversion occurs.
- The life of the catalyst is shortened because of the deactivation of the catalyst in high-temperature environments.
- The costs for the materials of construction are increased.

The materials of construction for a high-temperature catalyst require the surface to be plated with a Cr-Mo (Chromium- Molybdenum) steel alloy instead of carbon steel, which causes the costs to increase. Haldor-Topsoe indicates that the costs for using a high-temperature catalyst versus a low-temperature catalyst will increase the catalyst cost by at least two to three times and also increase the operational as well.

Another catalyst vendor, Cormetech, provides a high-temperature catalyst that has a temperature range of 870° F to 1100° F. However, Cormetech notes that the allowable temperature excursions are to be no more than 50 hours at 1112° F without appreciable catalyst activity loss. Haldor Topsoe offers a similar catalyst designed to have a normal operating temperature at 600° F to 750° F with a limit of 50 hours for temperature excursions at 1050° F. As discussed above, a high-temperature catalyst requires more catalyst volume. As the volume of catalyst is increased, the following issues become items of concern: the pressure drop across the catalyst increases (unless the duct work is expanded), more SO_2 to SO_3 conversion occurs, the life of the catalyst is shortened due to the deactivation of the catalyst in high temperature environments, and the costs for the material for construction are increased.

The exhaust temperatures at the exit of GEC Unit 1 and Unit 2 without the dilution air systems are between 1040° to 1200° F. Considering GEC Unit 1 and Unit 2 are proposed to fire natural gas for 3,000 hours per unit per year and ULSFO for 500 hours per unit per year or fire ULSFO for 1,000 hours per unit per year, the number of hours on either operating scenario far exceeds the limitations that any vendor is willing to guarantee for temperature excursions. It is not technically feasible to apply this technology to this Project and it will be eliminated from further evaluation in this BACT analysis.

3.2 Step 1--Identify All CO Control Technologies

The first step in a top-down analysis, according to the USEPA's October 1990, Draft New Source Review Workshop Manual, is to identify all available control options. Available control options are those air pollution control technologies or techniques with a practical potential for application to the emission unit and the CO emission limit that is being evaluated.

Typically, measures taken to minimize the formation of NO_x during combustion inhibit complete combustion, which increase the emissions of CO. Carbon monoxide is formed during the combustion process due to incomplete oxidation of the carbon contained in the fuel. CO formation is limited by ensuring complete and efficient combustion of the fuel in the combustion turbine. High combustion temperatures, adequate excess air, and good air/fuel mixing during combustion minimize CO emissions.

Carbon monoxide control methods may be divided into two categories: in-combustor CO formation control and post-combustion emission reduction. An in-combustor CO formation control process minimizes the quantity of CO formed in the combustion process. A post-combustion technology reduces the CO emissions in the flue gas stream after the CO has been formed in the combustion process. Both of these methods may be used alone or in combination to achieve the various degrees of CO emissions required. The three different types of emission controls reviewed by this BACT analysis are as noted below.

- In-Combustor Type:
  - Dry Low-NO_x (DLN) Burners.
- Post-Combustion Type:
  - Oxidation Catalyst.
  - $SCONO_x$.

The rationale behind whether the above technologies are evaluated as CO control for BACT is included in the following subsections.

3.2.1 Dry Low-NO_x Burners and Good Combustion Control

The development of good combustion practice improvements with state of the art DLN burners has reduced CO emissions as compared to those previously obtained by the use of water injection as the main NO_x control method. These improved combustion characteristics have allowed minimization of CO emissions without sacrificing NO_x control performance. For this reason, the use of low NO_x burners that use good combustion practices is the standard method of also controlling CO emissions.

3.2.2 CO Oxidation Catalyst

A current CO reduction technology available that will not impact NO_x emissions is the use of an oxidation catalyst to convert the CO to CO_2. The oxidation catalyst is typically a precious metal catalyst. None of the catalyst components are considered toxic. No reagent injection is necessary and oxidizing catalysts, dependent on the uncontrolled emission level, are capable of reducing a significant amount of the CO emissions. A 51.2 percent CO reduction rate (i.e. 4.1 ppm to 2 ppm for each SCCT) when firing natural gas, and a 75 percent reduction (i.e. 8.0 ppm to 2 ppm for each SCCT) when firing ULSFO has been assumed in this BACT analysis.

3.2.3 $SCONO_x$

Another CO control technology that was previously discussed for NO_x control is the $SCONO_x$ process. The $SCONO_x$ system reduces CO emissions by oxidizing the CO to CO_2. The demonstrated application for this technology is currently limited to combined cycle combustion turbine units under 45 MW. The combustion turbine proposed for this project is approximately 176 to 190 MW (depending on which fuel is being burned), which is outside the operating range (45 MW) of the $SCONO_x$ system currently operating at the Redding Electric Municipal Power Plant in California.

3.3 Step 2--Eliminate Technically Infeasible NO_x Options

Step 2 of the BACT analysis involves the evaluation of all the identified available control technologies in Step 1 of the BACT analysis to determine their technical feasibility. A control technology is technically feasible if it has been previously installed and operated successfully at a similar type of source of comparable size, or there is technical agreement that the technology can be applied to the source. Available and applicable are the two terms used to define the technical feasibility of a control technology. The following subsections review the control technologies identified in Step 1 of the NO_x BACT analysis and determine if they are technically feasible. Table 3-1 summarizes the evaluation of the technically feasible NO_x options.

3.3.1 Water or Steam Injection

Water or steam injection is a demonstrated technology of controlling NO_x emissions from a simple-cycle combustion turbine when firing fuel oil. It is commercially available from several vendors. Since GEC Unit 1 and Unit 2 will fire natural gas and ULSFO, water injection will only be used during ULSFO and will not be evaluated for the primary operating case of natural gas. Water injection is considered technically feasible and will be considered further.

3.3.2 Dry Low-NO_x Burners

Dry low-NO_x burners are a demonstrated technology of controlling NO_x emissions from a simple-cycle combustion turbine when firing natural gas and commercially available from several vendors. Dry low-NO_x burners are considered technically feasible and will be considered further.

3.3.3 XONON

Although XONON technology has been applied to small turbines, such as a Kawasaki M1A-13X (1.5 MW) combustion turbine, it has not been applied to utility size combustion turbines such as proposed for GEC Unit 1 and Unit 2. It is expected that application of this technology to utility size combustion turbines will require a period of "scale up" and testing before it can be determined that this technology can demonstrate in practice a given NO_x emission limit. Because this technology has not been applied to utility size combustion turbines firing natural gas or ULSFO, it is not considered to be technically feasible for GEC Unit 1 and Unit 2. As such, this method of combustion control will be eliminated from further evaluation for control of NO_x emissions in this BACT analysis.

Table 3-1
Summary of Step 2--Eliminate Technically Infeasible NO_x Options

Technology Alternative	Technically Feasible (Yes/No)	
	Available	Applicable
Water or Steam Injection	Yes	Yes –Not a primary control technology for natural gas fired turbines but feasible for ULSFO firing.
Dry Low-NO_x Burners	Yes	Yes
XONON	Yes	No – There are no documented installations on utility sized combustion turbines firing natural gas.
SNCR	Yes	No – The exhaust temperature of GEC Unit 1 and Unit 2 are less than the SNCR's optimum temperature range.
$SCONO_x$ with Dilution Air System	Yes	Yes
SCR with Dilution Air System	Yes	Yes
High-Temperature SCR	Yes	No – The number of hours firing natural gas or ULSFO for GEC Unit 1 and Unit 2 exceed the hours for allowable temperature excursions.

3.3.4 Selective Non-Catalytic Reduction

Selective non-catalytic reduction (SNCR) optimum temperature range for injection of ammonia or urea is 1,550° to 1,900° F. The exhaust temperature at the exit of the combustion turbines is between 1074° to 1200° F. Therefore, the exhaust temperature is less than the optimum temperature range for the application of this technology. It is not technically feasible to apply this technology to GEC Unit 1 and Unit 2 and it will be eliminated from further evaluation in this BACT analysis.

3.3.5 $SCONO_x$ with Dilution Air System

The application of this technology is currently limited to natural gas combined cycle combustion turbine units under 45 MW. However, EmeraChem, LLC is EM_X™ ($SCONO_x$) offers their product for GE 7FAs which makes it available. In addition, $SCONO_x$ has not been previously installed and operated at a similar type and size of turbine. However, in the interest of providing a complete technology analysis, $SCONO_x$ with dilution air system will be evaluated in the BACT for NO_x control.

3.3.6 Selective Catalytic Reduction with Dilution Air System

Selective Catalyst Reduction (SCR) with dilution air systems are a demonstrated technology of controlling NO_x emissions from simple-cycle combustion turbines and commercially available from several vendors. SCR with dilution air systems are considered technically feasible and will be considered further.

3.3.7 High-Temperature Selective Catalytic Reduction

High-temperature SCR has a limited number of hours for temperature excursions. The exhaust temperatures at the exit of GEC Unit 1 and Unit 2 without the dilution air systems are between 1040° to 1200° F. Considering the operational scenario basis for this BACT analysis (see Section 1.0), the number of hours on either fuel far exceeds the limitations that any vendor is willing to guarantee for temperature excursions. It is not technically feasible to apply this technology to this Project and it will be eliminated from further evaluation in this BACT analysis.

3.4 Step 2-Eliminate Technically Infeasible CO Options

Step 2 of the BACT analysis involves the evaluation of all the identified available control technologies in Step 1 of the BACT analysis to determine their technical feasibility. A control technology is technically feasible if it has been previously installed and operated successfully at a similar type of source of comparable size, or there is technical agreement that the technology can be applied to the source. Available and applicable are the two terms used to define the technical feasibility of a control technology. The following subsections review the control technologies identified in Step 1 of the CO BACT analysis and determine if they are technically feasible. Table 3-2 summarizes the evaluation of the technically feasible CO options.

3.4.1 Dry Low-NO_x Burners and Good Combustion Control

The development of good combustion practice improvements with state of the art DLN burners are a demonstrated technology of controlling CO emissions from a simple-cycle combustion turbine and commercially available from several vendors. DLN burners and good combustion control are considered technically feasible and will be considered further.

Table 3-2 Summary of Step 2--Eliminate Technically Infeasible CO Options		
Technology Alternative	Technically Feasible (Yes/No)	
	Available	Applicable
DLN Burners and Good Combustion Control	Yes	Yes
CO Oxidation Catalyst	Yes	Yes
$SCONO_x$	Yes	Yes

3.4.2 CO Oxidation Catalyst

CO oxidation catalysts are a demonstrated technology of controlling CO emissions from a simple-cycle combustion turbine and commercially available from several vendors. CO oxidation catalysts are considered technically feasible and will be considered further.

3.4.3 $SCONO_x$

The application of this technology is currently limited to natural gas combined cycle combustion turbine units under 45 MW. However, EmeraChem, LLC is EM_X^{TM} ($SCONO_x$) offers their product for GE 7FAs which makes it available. In addition, $SCONO_x$ has not been previously installed and operated at a similar type and size of turbine. However, in the interest of providing a complete technology analysis, $SCONO_x$ will be evaluated in the BACT for CO control.

3.5 Step 3-Rank Combined NO_x and CO Control Technology Effectiveness

In-combustor NO_x and CO control by advanced combustion controls using dry low NO_x burners is the least stringent control technology considered for GEC Unit 1 and Unit 2. However, the use of a combination SCR/oxidation catalyst system or the $SCONO_x$ system are technologies capable of achieving lower emissions than the application of dry low NO_x burners alone. Because the $SCONO_x$ system is capable of reducing NO_x and CO, emissions, the NO_x and CO BACT analyses have been combined to avoid double counting the $SCONO_x$ technology, thus inflating its economic impacts. The following control technologies will be evaluated in this BACT analysis and are ranked in order of relative control effectiveness:

- During natural gas firing, in-combustor NO_x and CO control consisting of DLN combustors to limit outlet emissions for all operating loads for GEC Unit 1 and Unit 2 are considered the base case scenario. During ULSFO firing, in-combustor NO_x and CO control consisting of water injection to limit outlet emissions for all operating loads for GEC Unit 1 and Unit 2 are considered the base case scenario. All modern combustion turbines of the type proposed for this Project which burn natural gas and ULSFO, include DLN combustors and water injection.
- The addition of an SCR system and oxidation catalyst to reduce outlet NO_x emissions from the natural gas fired to the level of 2 ppmvd and CO to 2 ppmvd emissions for the natural gas fired CTG. As for ULSFO firing, the SCR system and oxidation catalyst to reduce outlet NO_x emissions to 8 ppmvd and CO to 2 ppmvd.
- The addition of a $SCONO_x$ system to reduce outlet NO_x emissions from the natural gas fired CTG to the NO_x level of 2 ppmvd and CO emissions to 2 ppmvd. As for ULSFO firing, the $SCONO_x$ system to reduce outlet NO_x emission to 8 ppmvd and CO to 2 ppmvd.

The following evaluation considers energy, environmental, and economic impacts for the NO_x and CO combined technology scenarios evaluated when firing natural gas and ULSFO. For the case of firing ULSFO only (pre-onsite natural gas availability), Table 3-3 outlines the expected NO_x and CO emissions rates from the evaluated emissions control alternatives of dry low NO_x burners (i.e. good combustion controls), SCR/CO catalyst, and $SCONO_x$. For the case of firing 3,000 hours on natural gas and 500 hour on ULSFO per unit per year (post-onsite natural gas availability), Table 3-4 outlines the expected NO_x and CO emissions rates from the evaluated emissions control alternatives of dry low NO_x burners (i.e. good combustion controls), SCR/CO catalyst, and $SCONO_x$. For both fuels, SCR/CO catalyst and $SCONO_x$ are considered the most stringent NO_x and CO emissions control alternatives, as they achieve the lowest outlet emission rate. Therefore, if $SCONO_x$ is not found viable via energy, environmental, or economic impacts for the combined emissions reduction, the $SCONO_x$ technology will be eliminated from consideration, and the BACT evaluation will be completed for control of NO_x and CO emissions separately.

Table 3-3
Estimated NO_x and CO Emissions From Alternate Control Technologies For Each CTG
(ULSFO: Pre-Onsite Natural Gas Availability)

	Control Technology Alternatives		
	WI/Good Combustion Controls	SCR/CO Catalyst	$SCONO_x$
NO_x Emissions			
ppmvd (at 15 percent O_2)	42.0	8.0	8.0
lb/h	329.4	62.7	62.7
tons per year (tpy)[a]	164.7	31.4	31.4
percent reduction	N/A	81%	81%
NO_x Emission Reduction (tpy)	Base	133.3	133.3
CO Emissions			
ppmvd (at 15 percent O_2)	8.0	2.0	2.0
lb/h	38.2	9.6	9.6
tons per year (tpy)[a]	19.1	4.8	4.8
percent reduction	N/A	75%	75%
CO Emission Reduction (tpy)	Base	14.3	14.3

[a]Total emissions are based on firing only ULSFO for 1,000 hours per unit per year at ISO conditions.

Table 3-4
Estimated NO_x and CO Emissions From Alternate Control Technologies For Each CTG
(Natural Gas + ULSFO: Post-Onsite Natural Gas Availability)

	Control Technology Alternatives		
	LNB/Good Combustion Controls	SCR/CO Catalyst	$SCONO_x$
NO_x Emissions (natural gas)			
ppmvd (at 15 percent O_2)	9.0	2.0	2.0
lb/h	58.5	13	13
tons per year (tpy)[a]	87.8	19.5	19.5
percent reduction	N/A	78%	78%
NO_x Emission Reduction (tpy)	Base	68.3	68.3
NO_x Emissions (ULSFO)			
ppmvd (at 15 percent O_2)	42.0	8.0	8.0
lb/h	329.4	62.7	62.7
tons per year (tpy)[a]	82.4	15.7	15.7
percent reduction	N/A	81%	81%
NO_x Emission Reduction (tpy)	Base	66.7	66.7
Total NO_x Emission Reduction (tpy)	Base	135.0	135.0
CO Emissions (natural gas)			
ppmvd (at 15 percent O_2)	4.1	2.0	2.0
lb/h	16.2	7.9	7.9
tons per year (tpy)[a]	24.3	11.9	11.9
percent reduction	N/A	51%	51%
CO Emission Reduction (tpy)	Base	12.4	12.4
CO Emissions (ULSFO)			
ppmvd (at 15 percent O_2)	8.0	2.0	2.0
lb/h	38.2	9.6	9.6
tons per year (tpy)[a]	9.6	2.4	2.4
percent reduction	N/A	75%	75%
CO Emission Reduction (tpy)	Base	7.2	7.2
Total CO Emission Reduction	Base	19.6	19.6

[a]Total emissions are based on firing natural gas for 3,000 hours per unit per year and ULSFO for 500 hours per unit per year.

3.6 Step 4-Evaluate Most Effective Combined NO_x and CO Controls

In the following subsections, the NO_x and CO combined control technologies are evaluated in a comparative approach with respect to their energy, environmental, and economic impacts on GEC Unit 1 and Unit 2. The following are the evaluated technologies: $SCONO_x$, SCR, and Oxidation Catalyst.

3.6.1 $SCONO_x$ Energy Impacts

The use of a $SCONO_x$ system will increase the energy requirements on the system compared to use of dry low NO_x burners alone. The $SCONO_x$ system will increase the backpressure on the combustion turbine by about 4 inches water gauge (in. w.g.). The dilution air system will have approximately 10 in. w.g. across the fan. The increase in backpressure and extra fan capacity will reduce the output for each CTG by approximately 1 percent and increase the lost power generation for each unit. In addition, the period required for catalyst washing will result in increasing the lost power generation. Wahlco-Metroflex estimated the unit will be offline for a 24 hour period once per year to accommodate the washing process. Furthermore, there will be an energy loss due to steam consumption from the regeneration system. Steam is used as the carrier medium for the regeneration gas for the $SCONO_x$ system. Wahlco-Metroflex estimated that approximately 5,000 lb/h of steam would be used in the regeneration production for each combustion turbine. These three effects will be added together to determine the total lost power generation and are included in the annualized cost estimate. The $SCONO_x$ system will have minimal effect on power consumption that will be necessary to operate the damper actuators and regeneration system. Wahlco-Metroflex estimated that approximately 15 kW would be consumed during operation of each $SCONO_x$ system. This increase in power consumption will be included in the annualized cost estimate. The natural gas required for the production of the regeneration gas will increase the annualized cost associated with using the $SCONO_x$ system. The annualized cost of natural gas consumption is included in the annualized cost analysis.

3.6.2 $SCONO_x$ Environmental Impacts

The $SCONO_x$ catalyst is composed of precious metals coated with potassium carbonate. When the potassium carbonate coating can no longer be regenerated, the precious metal content of the remaining catalyst can be recycled. Although recycling the potassium carbonate is a positive aspect of this technology, the oxidation of CO and VOC that results from the application of this technology directly results in an increased production of CO_2, a greenhouse gas.

The $SCONO_x$ catalyst will oxidize approximately 1.0 percent of the SO_2 in the flue gas to SO_3. The SO_3 will then react with the moisture in the flue gas to form sulfuric acid mist in the atmosphere. Any sulfuric acid mist formed will increase the amount of particulate matter emitted in the flue gas. The particulate matter will predominately consist of PM_{10}.

3.6.3 SCR Energy Impacts

The use of an SCR system impacts the energy requirements of GEC Unit 1 and Unit 2. An SCR system requires an ammonia storage, handling and delivery system, which would include vaporizers and blowers to vaporize and dilute the ammonia reagent for injection. In addition, an SCR system catalyst would increase the backpressure on each combustion turbine. Firing natural gas, the SCR system would add about 1.8 inches water gauge (in. w.g.) backpressure to each unit for the NO_x reduction to 2.0 ppmvd. The dilution air system will have approximately 10 in. w.g. across the fan. This would reduce the output of each CTG by approximately 845 kW. Firing ULSFO, the SCR system would add about 2.6 inches water gauge (in. w.g.) backpressure to each unit for the NO_x reduction to 2.0 ppmvd. The dilution air system will have approximately 10 in. w.g. across the fan. This would reduce the output of each CTG by approximately 1,045 kW.

3.6.4 SCR Environmental Impacts

The vanadium content of the SCR catalyst contributes to its classification as a special waste. At the end of useful catalyst life, the spent catalyst can be regenerated or disposed of in a special waste landfill. The regeneration of catalyst consists of washing the catalyst either onsite or offsite. If washing is done onsite, the firm/company/vendor that washes the catalyst removes the hazardous wash water and puts it in holding ponds (owned by the firm/company/vendor that washed the catalyst). Because of this, recycling of SCR catalysts for vanadium has become common.

The use of ammonia in an SCR system introduces an element of environmental risk. Ammonia is listed as a hazardous substance under Title III Section 302 of the Superfund Amendments and Reauthorization Act of 1986 (SARA). However, the storage and use of ammonia has been a relatively routine practice in utility power plants and industrial plant processes and is also regulated by USEPA's Chemical Accident Prevention Provisions. This BACT analysis is based on the use of aqueous ammonia that can be stored and used more safely than anhydrous ammonia. According to the Committee on *Toxicology* of the National Academy of Sciences and the Committee on Medical and Biological Effects of Environmental Pollutants (both of the National Research Council), the following threshold concentrations exist for ammonia:

Human Response	Concentration (ppm)
Immediate throat irritation	Equal to or greater than 400
Eye irritation	Equal to or greater than 700
Coughing	Equal to or greater than 1,700
Life threatening for short exposure	2,500 to 6,500
Rapidly fatal for short exposure	5,000 to 10,000

Some ammonia slip from the Combustion Turbines Unit 1 and Unit 2 stacks are unavoidable due to the imperfect distribution of the reagent and catalyst deactivation. Although ammonia emissions are not regulated nationally, the Northeast States for Coordinated Air Use Management (NESCAUM) has recommended an ammonia slip emissions limit of 10 ppmvd, unless that limit is shown to be inappropriate. Ammonia slip from an SCR system is one of the major design consideration that establishes catalyst life. Therefore, lower ammonia slip requirements ultimately limit catalyst life and dictate associated catalyst replacement. Exceeding the NESCAUM's recommendation, FDEP proposed an ammonia slip of 5 ppmvd for Treasure Coast, a combined cycle combustion turbine unit utilizing SCR. Based on the recent Treasure Coast air permit, an ammonia slip design value of 5 ppmvd at 15 percent O_2 is used for this analysis.

The SCR catalyst will oxidize approximately 2 to 3 percent of the SO_2 in the flue gas to SO_3. As indicated earlier, GEC Unit 1 and Unit 2 are assumed to have dilution air systems installed in order to accommodate the SCR's upper temperature range of 600 to 750° F. Once the flue gas cools below approximately 600° F, the ammonia present in the flue gas may react with SO_3 to form ammonium sulfate and bisulfate salts. This formation may be dependent on the particular plume dispersion characteristics at the given time of stack discharge, which is dependent upon the temperature reached once the flue gas has left the stack. However, if the ammonia sulfate compounds are not formed, the SO_3 will react with the moisture in the flue gas to form sulfuric acid mist in the atmosphere. Any ammonium sulfate and bisulfate salts and sulfuric acid mist formed will increase the amount of particulate matter emitted in the flue gas. The particulate material will predominately consist of matter less than PM_{10}. As the catalyst gradually deactivates, more ammonia must be injected to compensate and maintain the desired NO_x reduction. This results in an increased amount of ammonia slip for a given level of performance. Increased ammonia slip in turn results in additional ammonia salt formation which could result in increased opacity and particulate emissions from GEC Unit 1 and Unit 2.

3.6.5 *Oxidation Catalyst Energy Impacts*

An oxidation catalyst reactor located downstream of the combustion turbine exhaust will increase the backpressure on the combustion turbine. Firing natural gas, the additional backpressure of about 0.8 inches, water gauge, will reduce each combustion turbine output by approximately 158 kW. Firing ULSFO, the additional backpressure of about 1.0 inches, water gauge, will reduce each combustion turbine output by approximately 214 kW. The cost of lost power revenue due to the backpressure is included in the economic analysis.

3.6.6 *Oxidation Catalyst Environmental Impacts*

The major environmental disadvantage that exists when using an oxidation catalyst to reduce CO emissions is that a percentage of the SO_2 in the flue gas will oxidize to SO_3. The higher the operating temperature, the higher the SO_2 to SO_3 oxidation potential. It is estimated that approximately 20 percent of the SO_2 in the flue gas will oxidize to SO_3 as a result of the oxidation catalyst being installed after the combustion turbine outlet with high temperatures. The SO_3 will react with the moisture in the flue gas to form sulfuric acid mist (H_2SO_4). The increase in H_2SO_4 emissions would increase PM_{10} emissions.

Spent oxidation catalyst is made up of precious metals that are not considered toxic. This allows the catalyst to be handled and disposed of following normal waste procedures. Because of the precious metal content of the catalyst, the oxidation catalyst can also be recycled to recover the precious metals.

As mentioned previously, the installation of an oxidation catalyst will also increase the backpressure on the turbine, thereby decreasing efficiency. This decrease in efficiency will lead to increased emissions of all pollutants on a unit power output basis. The oxidation of CO also directly results in increased production of CO_2, a greenhouse gas.

3.6.7 *Economic Impacts for SCR / Oxidation Catalyst Versus SCONO$_x$*

The use of an SCR/oxidation catalyst or $SCONO_x$ has significant economic impacts to GEC Unit 1 and Unit 2. An analysis of the economic impact is provided in this section.

3.6.7.1 Capital Costs for SCR / Oxidation Catalyst and $SCONO_x$. Table 3-5 presents the capital costs for installing an SCR/oxidation catalyst and $SCONO_x$ system on each CTG during exclusive ULSFO firing (pre-onsite natural gas availability) to achieve a NO_x outlet emission level of 8.0 ppmvd and a CO outlet emission rate of 2.0 ppmvd. Table 3-6 presents the capital costs for installing an SCR/oxidation catalyst and $SCONO_x$ system on each CTG during natural gas and ULSFO firing scenario (post-onsite natural gas availability) to achieve a NO_x outlet emission level of 2.0 ppmvd and a CO outlet emission rate of 2.0 ppmvd while firing gas, and a NO_x outlet emission level of 8.0 ppmvd and a CO outlet emission rate of 2.0 ppmvd when firing ULSFO. Note, the same SCR/oxidation catalyst and $SCONO_x$ systems have been designed to accommodate the operating scenario of GEC Unit 1 and Unit 2 to fire natural gas for 3,000 hours per unit per year and ULSFO for 500 hours per unit per year. The cost of the SCR/oxidation catalyst system includes the ammonia receiving, storage, transfer, vaporization, and injection; catalytic reactor housing, ductwork, and dilution air system; controls and instrumentation and freight. The catalyst costs were not included in the total capital investment (TCI) cost but assessed as an annual cost. The cost of the $SCONO_x$ system includes the catalyst, regenerative gas distribution system, catalytic reactor housing, controls and instrumentation, and freight. The BOP cost for the SCR/oxidation catalyst and $SCONO_x$ system consist of 8 percent of the purchased equipment costs (PEC) for foundation and supports, 14 percent for handling and erection, 4 percent for electrical installation, 2 percent for piping, 1 percent for insulation, and 1 percent for painting. Capital costs were based on budgetary quotations from equipment manufacturers and other engineering estimates.

Quotations for the SCR and oxidation catalyst material were based on vanadium/titanium and precious metal type catalysts, respectively. The direct installation costs included the balance of plant items such as foundations, insulation and lagging and painting and were calculated as percentages of the total purchased equipment costs. The total capital investment was calculated as the summation of the total direct cost (DC) and total indirect costs (IC) per OAQPS cost methods. The indirect capital costs for the SCR/Oxidation Catalyst systems are percentages of the total direct costs (DC) and are site specific. The indirect capital costs for the $SCONO_x$ system are percentages of the $SCONO_x$ system DC.

Table 3-5
NO_x/CO Combined Control Alternative Capital Cost For Each CTG
(ULSFO: Pre-Onsite Natural Gas Availability)

	DLN/ WI	$SCONO_x$	SCR/OX Cat	Remarks
Direct Capital Cost				Cost based on emissions in Table 3-3
Catalysts	N/A	Included	1,821,000	Estimated from Turner EnviroLogic
Catalyst R. Housing/ Ductwork	N/A	Included	1,256,000	Estimated from Turner EnviroLogic
Dilution Air System	N/A	285,000	285,000	Estimated from Turner EnviroLogic
$SCONO_x$ System	N/A	16,000,000	0	Vendor Estimate
Control/Instrumentation	N/A	150,000	195,000	Estimated; includes controls and monitoring equipment.
Ammonia (Storage & Injection/Dilution)	N/A	N/A	985,000	Estimated from Turner EnviroLogic and previous projects.
Purchased Equipment Costs (PEC)	**N/A**	**16,435,000**	**4,542,000**	
Sales Tax		0	0	Not applicable to JEA
Freight	N/A	1,644,000	454,000	10% of PEC
Balance of Plant	N/A	5,588,000	1,362,000	30% of PEC. See text for background information on this item
Total Direct Cost (DC)	**N/A**	**23,667,000**	**6,358,000**	
Indirect Capital Costs				
Contingency	N/A	2,367,000	636,000	10% of DC
Engineering and Supervision	N/A	2,367,000	636,000	10% of DC for $SCONO_x$. 10% of DC for SCR and 10% of DC for CO catalyst.
Construction & Field Expense	N/A	1,183,000	318,000	5% of DC
Construction Fee	N/A	2,367,000	636,000	10% of DC
Start-up Assistance	N/A	473,000	128,000	2% of DC
Performance Test	N/A	50,000	50,000	Assumed $50,000 emission test.
Total Indirect Capital Costs (IC)	**Base**	**8,807,000**	**2,404,000**	
Installed Costs (DC+IC)	**Base**	**32,474,000**	**8,762,000**	
Less Catalyst	Base	4,000,000	1,821,000	Catalyst is viewed as an O&M value.
Total Capital Investment (TCI)	**Base**	**28,474,000**	**6,941,000**	TCI = DC + IC – Catalyst

Table 3-6
NO_x/CO Combined Control Alternative Capital Cost For Each CTG
(Natural Gas + ULSFO: Post-Onsite Natural Gas Availability)

	DLN	$SCONO_x$	SCR/OX Cat	Remarks
Direct Capital Cost				Cost based on emissions in Table 3-4
Catalysts	N/A	Included	1,913,000	Estimated from Turner EnviroLogic
Catalyst R. Housing /Ductwork	N/A	Included	1,256,000	Estimated from Turner EnviroLogic
Dilution Air System	N/A	285,000	285,000	Estimated from Turner EnviroLogic
$SCONO_x$ System	N/A	16,000,000	0	Vendor Estimate
Control/Instrumentation	N/A	150,000	195,000	Estimated; includes controls and monitoring equipment.
Ammonia (Storage & Injection/Dilution)	N/A	N/A	985,000	Estimated from Turner EnviroLogic and previous projects.
Purchased Equipment Costs (PEC)	**N/A**	**16,435,000**	**4,634,000**	
Sales Tax		0	0	Not applicable to JEA
Freight	N/A	1,644,000	163,000	10% of PEC
Balance of Plant	N/A	5,588,000	1,390,000	30% of PEC. See text for background information on this item
Total Direct Cost (DC)	**N/A**	**23,667,000**	**6,487,000**	
Indirect Capital Costs				
Contingency	N/A	2,367,000	648,000	10% of DC
Engineering and Supervision	N/A	2,367,000	648,000	10% of DC for $SCONO_x$. 10% of DC for SCR and 10% of DC for CO catalyst.
Construction & Field Expense	N/A	1,183,000	325,000	5% of DC
Construction Fee	N/A	2,367,000	648,000	10% of DC
Start-up Assistance	N/A	473,000	130,000	2% of DC
Performance Test	N/A	50,000	50,000	Assumed $50,000 emission test.
Total Indirect Capital Costs (IC)	**Base**	**8,807,000**	**2,449,000**	
Installed Costs (DC+IC)	**Base**	**32,474,000**	**8,936,000**	
Less Catalyst	Base	4,000,000	1,913,000	Catalyst is viewed as an O&M value.
Total Capital Investment (TCI)	**Base**	**28,474,000**	**7,023,000**	TCI = DC + IC – Catalyst

There are many potential items and uncertainties that are not captured by the cost items included in the estimate, such as possible changes between cost quotes and contract values, changes in operating conditions, process contingency, increased equipment cost, scope changes, labor/wage increases, and schedule acceleration. In addition, the Electric Power Research Institute published the document titled, NO_x Emissions: Best Available Control Technology, A Gas Turbine Permitting Guidebook in November 1991 and list under NO_x control cost (Page 5-5) the following text:

> "Based on experience with other cost methodology sources, the contingency factor recommended by the OAQPS Manual (3% of the total equipment cost) is a lower-bound estimate. Standard EPA guidance for pollution control costing is a contingency factor of 10 to 50% of the sum of direct and indirect costs.[1] A contingency factor of 20% of the sum of direct and indirect costs was used in the economic analyses conducted by the EPA in support of the NSPS for industrial and small boilers and municipal waste combustors.[2,3]. Based on this range of values, it is recommended that individual utilities use the contingency factor that would normally be used in-house in procurement or rate estimation procedures, and document the validity of the factor for the case in question. The factor recommended by OAQPS should be used as a default value when more appropriate information is not available."

Therefore a 10 percent contingency factor has been assumed for this project.

Based on the analysis in this section, the total capital investment for the SCR/oxidation catalyst control system is calculated as the sum of the total direct and indirect capital costs per OAQPS cost methods. Firing ULSFO for 1,000 hours per unit per year (pre-onsite natural gas availability), the total capital investment for each CTG controlling NO_x and CO to 8.0 ppmvd and 2.0 ppmvd, respectively is estimated to be \$6,941,000. Firing natural gas for 3,000 hours per unit per year and ULSFO for 500 hours per unit per year (post-onsite natural gas availability scenario), the total capital investment for each CTG controlling NO_x and CO to 8.0 ppmvd and 2.0 ppmvd when firing ULSFO and controlling NOx and CO to 2.0 ppmvd when firing natural gas is estimated to be \$7,023,000.

The total capital investment for the $SCONO_x$ control system is calculated as the sum of the total direct and indirect capital costs per OAQPS cost methods. Firing ULSFO

[1] U.S. Environmental Protection Agency, A Standard Procedure for Cost Analysis of Pollution Control Operations: Volume I, EPA 600/8-79-018a, June 1979.

[2] U.S. Environmental Protection Agency, Industrial Boiler SO_2 Cost Report, EPA 450/3-85-011, November 1984.

[3] U.S. Environmental Protection Agency, Municipal Waste Combustors – Background Information for Proposed Standards: Control of NO_x Emissions, EPA 450/3-89-27d, August 1989.

for 1,000 hours per unit per year (pre-onsite natural gas availability), the total capital investment for each CTG controlling NO_x and CO to 8.0 ppmvd and 2.0 ppmvd respectively is estimated to be $28,474,000. Firing natural gas for 3,000 hours per unit per year and ULSFO for 500 hours per unit per year (post-onsite natural gas availability), the total capital investment for each CTG controlling NO_x and CO to 8.0 ppmvd and 2.0 ppmvd when firing ULSFO and controlling NO_x and CO to 2.0 ppmvd when firing natural gas is estimated to be $28,474,000.

3.6.7.2 Operating Costs for SCR/Oxidation Catalyst Versus SCONO$_x$. Table 3-7 presents the annualized operating costs using a SCR/oxidation catalyst and SCONO$_x$ system to achieve NO_x outlet emissions of 8.0 ppmvd and CO emissions of 2.0 ppmvd while firing ULSFO for GEC Unit 1 and Unit 2. Table 3-8 presents the annualized operating costs using a SCR/oxidation catalyst and SCONO$_x$ system to achieve NO_x outlet emissions of 2.0 ppmvd and CO emissions of 2.0 ppmvd while firing natural gas, and NO_x outlet emissions of 8.0 ppmvd and CO emissions of 2.0 ppmvd while firing ULSFO. Annualized operating costs for the SCR/oxidation catalyst include catalyst replacement, energy impacts, operating personnel, maintenance, reagent and heat rate penalty. Throughout the life of the plant, catalyst elements for both the SCR and the oxidation catalyst will require periodic replacement. As the SCR catalyst becomes deactivated, ammonia slip emissions will increase. At the point ammonia slip approaches 5 ppmvd the catalyst must be replaced. The oxidation catalyst will degrade from normal operation that will be evident by an increase in CO emissions, thereby requiring replacement of the oxidation catalyst. Currently, SCR and oxidation catalyst manufacturers are willing to guarantee a catalyst life of three years of equivalent operating hours.

Ammonia consumption rates were based on a stoichiometric ratio of 1.1 for reacting NO_x. The heat rate penalty cost (lost power generation) item reflects the cost due to the SCR and oxidation catalyst backpressure losses. The additional backpressure will derate the combustion turbine resulting in lost electric sales revenue. The costs associated with these impacts are included in the annualized cost estimate.

The use of either an SCR/oxidation catalyst system or a SCONO$_x$ system increases the energy requirements of the project. The SCR system requires vaporizers and blowers to vaporize and dilute the ammonia reagent for injection. SCONO$_x$ consumes power to open and close the catalyst dampers and to produce the regenerating gas. The maintenance costs will consist of routine system maintenance for each system. However, there is an additional annual maintenance cost for washing the SCONO$_x$/SCOSO$_x$ catalyst. Therefore, the SCONO$_x$ system will include the additional O&M cost for catalyst washing.

Table 3-7
NO_x/CO Combined Control Alternative Annualized Cost For Each CTG
(ULSFO: Pre-Onsite Natural Gas Availability)

	DLN	SCONOx	SCR/OX Cat	Remarks
Direct Annual Cost				Cost based on emissions in Table 3-3
Catalyst Replacement	N/A	1,116,000	767,000	Includes freight, installation, and 3-yr. capital recovery factor based on 3 yr. guaranteed catalyst life for SCR/OX cat and 5 year catalyst life for SCONOx.
Operation and Maintenance	N/A	8,000	4,000	See text for background information on this item
Maintenance Materials	N/A	48,000	23,000	
Reagent Feed	N/A	N/A	60,000	Assumes 1.1 stoichiometric ratio
Natural Gas Consumption	N/A	8,000	0	
Power Consumption	N/A	13,000	79,000	Includes injection blower and vaporization of ammonia
Lost Power Generation	N/A	2,081,000	79,000	Back pressure on combustion turbine. Includes seven days of lost power generation time for catalyst/system cleaning for $SCONO_x$
Annual Distribution Check	N/A	118,000	44,000	Estimated as 0.5% of the total direct cost for $SCONO_x$ and 1% for SCR
Total Direct Annual Cost	**N/A**	**3,392,000**	**1,056,000**	
Indirect Annual Costs				
Overhead	N/A	5,000	2,000	60% of O&M Cost
Administrative Charges	N/A	649,000	175,000	2% of Installed Cost
Property Taxes	N/A	0	0	Not included
Insurance	N/A	325,000	88,000	1% of Installed Cost
Capital Recovery	N/A	2,285,000	557,000	Capital Recovery Excluding Catalyst
Total Indirect Annual Costs	**N/A**	**3,264,000**	**822,000**	
Total Annualized Cost	**N/A**	**6,656,000**	**1,878,000**	

Table 3-8
NO_x/CO Combined Control Alternative Annualized Cost For Each CTG
(Natural Gas + ULSFO: Post-Onsite Natural Gas Availability)

	DLN	SCONOx	SCR/OX Cat	Remarks
Direct Annual Cost				Cost based on emissions in Table 3-4
Catalyst Replacement	N/A	1,116,000	807,000	Includes freight, installation, and 3-yr. capital recovery factor based on 3 yr. guaranteed catalyst life for SCR/OX cat and 5 year catalyst life for SCONOx.
Operation and Maintenance	N/A	27,000	15,000	See text for background information on this item
Maintenance Materials	N/A	48,000	23,000	
Reagent Feed	N/A	N/A	75,000	Assumes 1.1 stoichiometric ratio
Natural Gas Consumption	N/A	26,000	0	
Power Consumption	N/A	44,000	98,000	Includes injection blower and vaporization of ammonia
Lost Power Generation	N/A	2,293,000	264,000	Back pressure on combustion turbine. Includes seven days of lost power generation time for catalyst/system cleaning for $SCONO_x$
Annual Distribution Check	N/A	118,000	46,000	Estimated as 0.5% of the total direct cost for $SCONO_x$ and 1% for SCR
Total Direct Annual Cost	**N/A**	**3,672,000**	**1,328,000**	
Indirect Annual Costs				
Overhead	N/A	16,000	9,000	60% of O&M Cost
Administrative Charges	N/A	649,000	178,000	2% of Installed Cost
Property Taxes	N/A	0	0	Not included
Insurance	N/A	325,000	90,000	1% of Installed Cost
Capital Recovery	N/A	2,285,000	564,000	Capital Recovery Excluding Catalyst
Total Indirect Annual Costs	**N/A**	**3,275,000**	**841,000**	
Total Annualized Cost	**N/A**	**6,947,000**	**2,169,000**	

The indirect annual costs include capital recovery, overhead, administrative charges and insurance. The overhead annual cost is estimated to be 60 percent of the O&M costs. According to the OAQPS Cost Manual there are two types of overhead, payroll and plant. Payroll overhead expenses include workmen's compensation, social security, vacations, group insurance and other fringe benefits. Plant overhead is not tied into O&M of the control system, but is related to plant protection, control labs, employee amenities, plant lighting, parking areas, and landscaping. The OAQPS Cost Manual allows one to combine these overhead cost into one sum. The administrative cost covers sales, research and development, accounting, and other home office expenses. The insurance cost was based on 1 percent of the total capital investment for each system.

3.6.7.3 Total Annualized Costs for SCR / Oxidation Catalyst Versus SCONO$_x$. Total annualized costs for the SCR and oxidation catalyst control systems are calculated as the sum of operating costs plus the system capital recovery cost. The system capital recovery cost is the product of the system capital recovery factor (CRF) and the total capital investment (TCI). Table 3-7 shows the total annualized cost for SCR/Oxidation Catalyst systems for each CTG firing 1,000 hours per unit per year on ULSFO (pre-onsite natural gas availability) is estimated to be $1,878,000, which is also approximately a fourth of the cost of a SCONO$_x$ system having a total annualized cost of $6,656,000. Table 3-8 shows the total annualized cost for a SCR/Oxidation Catalyst systems for each CTG firing 3,000 hours per unit per year on natural gas and 500 hours per unit per year on ULSFO (post-onsite natural gas availability) is estimated to be $2,169,000, which is approximately a third of the cost of a SCONO$_x$ system having a total annualized cost of $6,947,000.

3.6.7.4 Conclusions. Based on the fact that the SCR/oxidation catalyst system is a lower capital cost system and has lower annualized costs than the SCONO$_x$ system for either firing natural gas or ULSFO, the SCONOx system will not be further evaluated as part of the BACT analysis. The remainder of the BACT analysis will concentrate on evaluating technologies for the control of each pollutant separately.

3.7 Step 4-Evaluate Most Effective NO_x Controls

The following section identifies economic impacts of the NO_x only BACT analysis. This section will not include a discussion of energy and environmental impacts, as they are the same as those discussed in the combined control BACT evaluation for NO_x and CO as listed in Section 3.6.

3.7.1 Economic Impacts for SCR

An economic analysis of SCR as a control technology for controlling NO_x emissions to 8.0 ppmvd while firing ULSFO and 2.0 ppmvd while firing natural gas is provided in this section.

3.7.2 Economic Impacts for SCR System

The use of an SCR has significant economic impacts to the JEA Project. The application of SCR on GEC Unit 1 and Unit 2 must incorporate special design and operational/maintenance criteria, such as periodic catalyst replacements and increased associated plant outage costs. A detailed description of the economic impacts of SCR was provided previously in Subsection 3.6.7 and will not be repeated.

3.7.2.1 Capital Costs for SCR. Table 3-9 summarizes the economic capital cost for implementing SCR on each CTG firing 1,000 hours per unit per year of ULSFO (pre-onsite natural gas availability). Table 3-10 summarizes the economic capital cost for implementing SCR on each CTG firing 3,000 hours on natural gas and 500 hours per unit per year on ULSFO (post-onsite natural gas availability). Based on the analysis in this section, the total installed capital costs for the SCR control system is calculated as the sum of the total direct and indirect capital costs per OAQPS cost methods. The total capital investment cost of SCR for each CTG controlling NO_x to 8.0 ppmvd while firing ULSFO (pre-onsite natural gas availability) is estimated to be \$4,976,000. The total capital investment cost of SCR for each CTG controlling NO_x to 2.0 ppmvd while firing natural gas and 8.0 ppmvd when firing ULSFO (post-onsite natural gas availability) is estimated to be \$5,058,000.

3.7.2.2 Total Annualized Costs for SCR. Total annualized costs for the SCR control systems are calculated as the sum of operating costs plus the system capital recovery cost. The system capital recovery cost is the product of the system capital recovery factor (CRF) and the total capital investment (TCI). Firing 1,000 hours per unit per year on ULSFO (pre-onsite natural gas availability), Table 3-11 shows the total annualized cost for a SCR system is estimated to be \$1,354,000. This annualized cost for the each CTG SCR system results in a cost effectiveness of approximately \$10,155 per ton of NO_x removed. Firing natural gas for 3,000 hours per unit per year and ULSFO for 500 hours per unit per year (post-onsite natural gas availability), Table 3-12 shows the total annualized cost for a SCR system is estimated to be \$1,621,000. This annualized cost for the each CTG SCR system results in a cost effectiveness of approximately \$12,015 per ton of NO_x removed.

Table 3-9
NO_x Emission Control Alternative Capital Cost For Each CTG
(ULSFO: Pre-Onsite Natural Gas Firing Scenario)

	DLN	SCR	Remarks
Direct Capital Cost			Cost based on emissions in Table 3-3.
Catalyst	N/A	1,113,000	Estimated from Turner EnviroLogic
Catalyst R. Housing /Ductwork	N/A	628,000	Estimated from Turner EnviroLogic
Dilution Air System	N/A	285,000	Estimated from Turner EnviroLogic
Control/Instrumentation	N/A	150,000	Estimated; includes controls and monitoring equipment.
Ammonia (Injection/Dilution/ Storage)	N/A	985,000	Estimated from Turner EnviroLogic and previous projects.
Purchased Equipment Costs (PEC)	**N/A**	**3,161,000**	
Sales Tax		0	Not applicable to JEA.
Freight	N/A	316,000	10% of PEC
Balance of Plant	N/A	948,000	30% of PEC. See text for background information on this item.
Total Direct Cost (DC)	**Base**	**4,425,000**	
Indirect Capital Costs			
Contingency	N/A	443,000	10% of DC
Engineering and Supervision	N/A	443,000	10% of DC
Construction & Field Expense	N/A	221,000	5% of DC
Construction Fee	N/A	443,000	10% of DC
Start-up Assistance	N/A	89,000	2% of DC
Performance Test	N/A	25,000	Assumed $25,000
Total Indirect Capital Costs (IC)	**Base**	**1,664,000**	
Installed Costs (DC + IC)		**6,089,000**	
Less SCR Catalyst Cost		1,113,000	Catalyst is viewed as an O&M value.
Total Capital Investment, TCI	**Base**	**4,976,000**	

Table 3-10
NO_x Emission Control Alternative Capital Cost For Each CTG
(Natural Gas + ULSFO: Post-Onsite Natural Gas Firing Scenario)

	DLN	SCR	Remarks
Direct Capital Cost			Cost based on emissions in Table 3-4.
Catalyst	N/A	1,205,000	Estimated from Turner EnviroLogic
Catalyst R. Housing /Ductwork	N/A	628,000	Estimated from Turner EnviroLogic
Dilution Air System	N/A	285,000	Estimated from Turner EnviroLogic
Control/Instrumentation	N/A	150,000	Estimated; includes controls and monitoring equipment.
Ammonia (Injection/Dilution/ Storage)	N/A	985,000	Estimated from Turner EnviroLogic and previous projects.
Purchased Equipment Costs (PEC)	**N/A**	**3,253,000**	
Sales Tax		0	Not applicable to JEA.
Freight	N/A	325,000	10% of PEC
Balance of Plant	N/A	976,000	30% of PEC. See text for background information on this item.
Total Direct Cost (DC)	**Base**	**4,554,000**	
Indirect Capital Costs			
Contingency	N/A	455,000	10% of DC
Engineering and Supervision	N/A	455,000	10% of DC
Construction & Field Expense	N/A	228,000	5% of DC
Construction Fee	N/A	455,000	10% of DC
Start-up Assistance	N/A	91,000	2% of DC
Performance Test	N/A	25,000	Assumed $25,000
Total Indirect Capital Costs (IC)	**Base**	**1,709,000**	
Installed Costs (DC + IC)		**6,263,000**	
Less SCR Catalyst Cost		1,205,000	Catalyst is viewed as an O&M value.
Total Capital Investment, TCI	**Base**	**5,058,000**	

Table 3-11
NO_x Emissions Control Annualized Cost For Each CTG
(ULSFO: Pre-Onsite Natural Gas Firing Scenario)

	DLN/ WI	SCR	Remarks
Direct Annual Cost			Cost based on emissions in Table 3-3
Catalyst Replacement	N/A	494,000	Includes freight, installation, and 3-yr capital recovery factor based on 3 yr. guaranteed catalyst life
Operation and Maintenance	N/A	4,000	See text for background information
Maintenance Materials	N/A	23,000	See text for background information
Reagent Feed	N/A	60,000	Assumes 1.1 stoichiometric ratio
Power Consumption	N/A	79,000	Includes injection blowers and vaporization of ammonia
Lost Power Generation	N/A	66,000	Back pressure on combustion turbine
Annual Distribution Check	N/A	44,000	Estimated as 1 % of the total direct cost
Total Direct Annual Cost	N/A	770,000	
Indirect Annual Costs	N/A		
Overhead	N/A	2,000	60% of Operation and Maintenance cost
Administrative Charges	N/A	122,000	2% of Installed Costs
Property Taxes	N/A	0	Not included
Insurance	N/A	61,000	1% of Installed Costs
Capital Recovery	N/A	399,000	Capital recovery excluding catalyst
Total Indirect Annual Cost	N/A	584,000	
Total Annualized Cost	N/A	1,354,000	
NO_x Annual Emissions, tpy	164.7	31.4	Emission taken from Table 3-3
NO_x Emissions Reduction, tpy	N/A	133.3	Emissions calculated in Table 3-3
NO_x Total Cost Effectiveness, $/ton	N/A	10,155	Total Annualized Cost/Emissions Reduction

Table 3-12
NO_x Emissions Control Annualized Cost For Each CTG
(Natural Gas + ULSFO: Post-Onsite Natural Gas Firing Scenario)

	DLN	SCR	Remarks
Direct Annual Cost			Cost based on emissions in Table 3-4
Catalyst Replacement	N/A	534,000	Includes freight, installation, and 3-yr capital recovery factor based on 3 yr. guaranteed catalyst life
Operation and Maintenance	N/A	15,000	See text for background information
Maintenance Materials	N/A	23,000	See text for background information
Reagent Feed	N/A	75,000	Assumes 1.1 stoichiometric ratio
Power Consumption	N/A	98,000	Includes injection blowers and vaporization of ammonia
Lost Power Generation	N/A	227,000	Back pressure on combustion turbine
Annual Distribution Check	N/A	46,000	Estimated as 1 % of the total direct cost
Total Direct Annual Cost	N/A	1,018,000	
Indirect Annual Costs	N/A		
Overhead	N/A	9,000	60% of Operation and Maintenance cost
Administrative Charges	N/A	125,000	2% of Installed Costs
Property Taxes	N/A	0	Not included
Insurance	N/A	63,000	1% of Installed Costs
Capital Recovery	N/A	406,000	Capital recovery excluding catalyst
Total Indirect Annual Cost	N/A	603,000	
Total Annualized Cost	N/A	1,621,000	
NO_x Annual Emissions, tpy	170.1	35.2	Emission taken from Table 3-4
NO_x Emissions Reduction, tpy	N/A	134.9	Emissions calculated in Table 3-4
NO_x Total Cost Effectiveness, $/ton	N/A	12,015	Total Annualized Cost/Emissions Reduction

3.8 Step 4-Evaluate Most Effective CO Controls

The following section identifies economic impacts of the CO only BACT analysis. This section will not include a discussion of energy and environmental impacts, as they are the same as those discussed in the combined control BACT evaluation for NO_x and CO as listed in Section 3.6.

3.8.1 Economic Impacts for Oxidation Catalyst

The use of an oxidation catalyst has significant economic impacts to the JEA Project. An economic analysis of oxidation catalyst as a control technology for CO emissions of 2.0 ppmvd when firing natural gas and ULSFO, respectively, is provided in this section.

3.8.2 Capital Cost for Oxidation Catalyst

Table 3-13 presents the capital costs for installing an oxidation catalyst on the units when firing ULSFO for 1,000 hours per year per unit (pre-onsite natural gas availability) to achieve a CO outlet emission level of 2.0 ppmvd. Table 3-14 presents the capital costs for installing an oxidation catalyst on the units when firing natural gas for 3,000 hours per unit per year, and ULSFO for 500 hours per unit per year (post-onsite natural gas availability) to achieve a CO outlet emission level of 2.0 ppmvd. The capital costs for the systems includes the oxidation catalyst, oxidation catalyst reactor housing, controls and instrumentation, sales taxes and freight, and were based on budgetary quotations from equipment manufacturers and other engineering estimates. The direct installation costs included the balance of plant items such as foundations, insulation and lagging, and painting, and were calculated as percentages of the total purchased equipment costs (PEC). The total capital investment was calculated as the summation of the total direct cost (DC) and total indirect costs (IC) per OAQPS cost methods. The indirect capital costs for the SCR/Oxidation Catalyst systems are percentages of the total direct cost (DC) and are site specific. The three percent contingency value suggested in the OAQPS Cost Control Manual is judged to be inaccurate as compared to actual values typically used in the construction field for this level of estimating, as discussed in Section 3.6.7.1.

Total capital cost for the oxidation catalyst control system to reduce CO is calculated as the sum of the direct and indirect installed costs. The total capital investment per unit for an oxidation catalyst system to reduce CO emissions from each CTG firing 1,000 hours per unit per year of ULSFO is estimated to be $1,965,000. The total capital investment per unit for an oxidation catalyst system to reduce CO emissions from each CTG firing 3,000 hours of natural gas per unit per year and 500 hours per unit per year on ULSFO is estimated to be $1,965,000.

Table 3-13
CO Reduction System Capital Cost For Each CTG
(ULSFO: Pre-Onsite Natural Gas Availability)

	Good Combustion Controls/DLN	Oxidation Catalyst	Remarks
Direct Capital Cost			Cost based on emissions in Tables 3-3.
Oxidation Catalyst	N/A	708,000	Estimated from Turner EnviroLogic
Catalyst Reactor Housing / Ductwork	N/A	628,000	
Control/Instrumentation	N/A	45,000	Estimated; includes controls and monitoring equipment.
Purchased Equipment Costs (PEC)	N/A	1,381,000	
Sales Tax	N/A	0	Not applicable to JEA
Freight	N/A	138,000	10% of PEC
Balance of Plant	N/A	414,000	30% of PEC. See text for background information on this item.
Total Direct Cost (DC)	**Base**	**1,933,000**	
Indirect Capital Costs	N/A		
Contingency	N/A	193,000	10% of DC
Engineering and Supervision	N/A	193,000	10% of DC
Construction & Field Expense	N/A	97,000	5% of DC
Construction Fee	N/A	193,000	10% of DC
Start-up Assistance	N/A	39,000	2% of DC
Performance Test	N/A	25,000	Assumed value of $25,000
Total Indirect Capital Costs (IC)	**Base**	**740,000**	
Installed Costs (DC +IC)		**2,673,000**	
Less Catalyst	N/A	708,000	Catalyst is viewed as an O&M Value.
Total Capital Investment, TCI	**Base**	**1,965,000**	

Table 3-14
CO Reduction System Capital Cost For Each CTG
(Natural Gas + ULSFO: Post-Onsite Natural Gas Availability)

	Good Combustion Controls/DLN	Oxidation Catalyst	Remarks
Direct Capital Cost			Cost based on emissions in Tables 3-4.
Oxidation Catalyst	N/A	708,000	Estimated from Turner EnviroLogic
Catalyst Reactor Housing / Ductwork	N/A	628,000	
Control/Instrumentation	N/A	45,000	Estimated; includes controls and monitoring equipment.
Purchased Equipment Costs (PEC)	N/A	1,381,000	
Sales Tax	N/A	0	Not applicable to JEA
Freight	N/A	138,000	10% of PEC
Balance of Plant	N/A	414,000	30% of PEC. See text for background information on this item.
Total Direct Cost (DC)	**Base**	**1,933,000**	
Indirect Capital Costs	N/A		
Contingency	N/A	193,000	10% of DC
Engineering and Supervision	N/A	193,000	10% of DC
Construction & Field Expense	N/A	97,000	5% of DC
Construction Fee	N/A	193,000	10% of DC
Start-up Assistance	N/A	39,000	2% of DC
Performance Test	N/A	25,000	Assumed value of $25,000
Total Indirect Capital Costs (IC)	**Base**	**740,000**	
Installed Costs (DC +IC)		**2,673,000**	
Less Catalyst	N/A	708,000	Catalyst is viewed as an O&M Value.
Total Capital Investment, TCI	**Base**	**1,965,000**	

3.8.3 Operating Costs for Oxidation Catalyst

Table 3-15 and Table 3-16 present the annualized operating costs and emission rates using an oxidation catalyst to reduce CO emissions for the pre- and post-onsite natural gas availability scenarios, respectively. Annualized operating costs for the system includes catalyst replacement and lost power generation. Throughout the life of the plant, catalyst elements will require periodic replacement. Currently, catalyst manufacturers are willing to guarantee an oxidation catalyst life of three years of equivalent operating hours for an oxidation catalyst.

3.8.4 Total Annualized Costs for Oxidation Catalyst

Total annualized costs for the oxidation control system is calculated as the sum of operating costs plus the system capital recovery cost. The system capital recovery cost is the product of the system capital recovery factor (CRF) and the total installed costs. Firing exclusively 1,000 hours per unit per year on ULSFO (pre-onsite natural gas availability), the total annualized cost for a 2.0 ppmvd CO oxidation catalyst systems for each CTG is estimated to be $524,000. This annualized cost for each CTG results in a cost effectiveness of approximately $36,643 per ton of CO removed. Firing 3,000 hours per unit per year on natural gas and 500 hours per unit per year on ULSFO (post-onsite natural gas availability), the total annualized cost for a 2.0 ppmvd CO oxidation catalyst systems for each CTG is estimated to be $548,000. This annualized cost for each CTG results in a cost effectiveness of approximately $27,959 per ton of CO removed.

3.9 Step 5-Select NO_x BACT

Based on the high cost effectiveness value for the SCR catalyst, it is determined that add-on controls to further reduce NO_x emissions are unwarranted given the low NO_x emission characteristics of GEC Unit 1 and Unit 2 firing natural gas or ULSFO. Additionally, the limitation JEA is proposing for hours of operation for each CTG further validate that SCR catalyst is not required.

JEA has determined that the top NO_x control alternative when firing natural gas, Dry Low-NO_x (DLN) Burners, represents NO_x BACT for the GEC Unit 1 and Unit 2, corresponding to an emissions limit of 9.0 ppmvd at 15 percent O_2 on a 24 hour block average basis. The top NO_x control alternative when firing ULSFO, Water Injection (WI), represents NO_x BACT for the GEC Unit 1 and Unit 2, corresponding to an emissions limit of 42.0 ppmvd at 15 percent O_2 on a 24 hour average basis. Table 3-17 summarizes the Project's NO_x BACT determination for the GEC Unit 1 and Unit 2.

Table 3-15
CO Control Annualized Cost For Each CTG
(ULSFO: Pre-Onsite Natural Gas Availability)

	Good Combustion Controls/DLN	Oxidation Catalyst	Remarks
Direct Annual Cost			Cost based on emissions in Tables 3-3.
Catalyst Replacement	N/A	273,000	Includes freight, installation, and 3-yr. capital recovery factor based on 3 yr. guaranteed catalyst life.
Operation and Maintenance	N/A	0	Not applicable for Oxidation Catalyst
Lost Power Generation		13,000	Back pressure on combustion turbine
Total Direct Annual Cost	**N/A**	**286,000**	
Indirect Annual Costs			
Overhead	N/A	0	Not Applicable because of zero O&M
Administrative Charges	N/A	53,000	2% of Installed Costs
Property Taxes	N/A	0	Not included
Insurance	N/A	27,000	1% of Installed Costs
Capital Recovery	N/A	158,000	Capital recovery excluding catalyst.
Total Indirect Annual Costs	**N/A**	**238,000**	
Total Annualized Cost	**Base**	**524,000**	
CO Annual Emissions, tpy	19.1	4.8	Emissions taken from Table 3-3.
CO Emissions Reduction, tpy	N/A	14.3	Emissions taken from Table 3-3.
CO Total Cost Effectiveness, $/ton	**N/A**	**36,643**	**Total Annualized Cost/Emissions Reduction**

Table 3-16
CO Control Annualized Cost For Each CTG
(Natural Gas + ULSFO: Post-Onsite Natural Gas Availability)

	Good Combustion Controls/DLN	Oxidation Catalyst	Remarks
Direct Annual Cost			Cost based on emissions in Tables 3-4.
Catalyst Replacement	N/A	273,000	Includes freight, installation, and 3-yr. capital recovery factor based on 3 yr. guaranteed catalyst life.
Operation and Maintenance	N/A	0	Not applicable for Oxidation Catalyst
Lost Power Generation		37,000	Back pressure on combustion turbine
Total Direct Annual Cost	**N/A**	**310,000**	
Indirect Annual Costs			
Overhead	N/A	0	Not Applicable because of zero O&M
Administrative Charges	N/A	53,000	2% of Installed Costs
Property Taxes	N/A	0	Not included
Insurance	N/A	27,000	1% of Installed Costs
Capital Recovery	N/A	158,000	Capital recovery excluding catalyst.
Total Indirect Annual Costs	**N/A**	**238,000**	
Total Annualized Cost	**Base**	**548,000**	
CO Annual Emissions, tpy	33.9	14.3	Emissions taken from Table 3-4.
CO Emissions Reduction, tpy	N/A	19.6	Emissions taken from Table 3-4.
CO Total Cost Effectiveness, $/ton	**N/A**	**27,959**	**Total Annualized Cost/Emissions Reduction**

Table 3-17 GEC Unit 1 and Unit 2 NO_x BACT Determination	
Control Technology	Emission Limit
DLN Burners/WI	Natural Gas: 9.0 ppmvd @ 15% O_2 (24-hr avg.) ULSFO: 42.0 ppmvd @ 15% O_2 (24-hr avg.)

3.10 Step 5-Select CO BACT

Based on the high cost effectiveness value for the oxidation catalyst, it is determined that add-on controls to further reduce CO emissions are unwarranted given the low CO emission characteristics of GEC Unit 1 and Unit 2 firing natural gas or ULSFO. Additionally, the limitation JEA is accepting on hours of operation for each CTG further validate that oxidation catalyst is not required.

JEA has determined that the top CO control alternative when firing natural gas, Good Combustion Controls, represents CO BACT for the GEC Unit 1 and Unit 2, corresponding to an emissions limit of 4.1 ppmvd at 15 percent O_2 on a 24-hour block. The top CO control alternative when firing ULSFO, Good Combustion Controls, represents CO BACT for the GEC Unit 1 and Unit 2, corresponding to an emissions limit of 8.0 ppmvd at 15 percent O_2 on a 24-hour block. Table 3-18 summarizes the Project's CO BACT determination for the GEC Unit 1 and Unit 2.

Table 3-18 GEC Unit 1 and Unit 2 CO BACT Determination	
Control Technology	Emission Limit
Good Combustion Controls	Natural Gas: 4.1 ppmvd @ 15% O_2 (24-hr block) ULSFO: 8.0 ppmvd @ 15% O_2 (24-hr block)

4.0 GEC Unit 1 and Unit 2 PM/PM_{10} BACT Analysis

The objective of this analysis was to determine BACT for PM/PM_{10} emissions from GEC Unit 1 and Unit 2.

PM/PM_{10} emissions from the combustion turbines are a result of incomplete combustion and trace particulates in the fuel. The emissions of particulate matter from GEC Unit 1 and Unit 2 will be controlled by ensuring as complete combustion of the fuel as possible. The NSPS for combustion turbines do not establish a particulate emission limit. Natural gas contains only trace quantities of non-combustible material. As for ULSFO, it contains small quantities of non-combustible material.

The manufacturer's standard operating procedures include filtering the turbine inlet air and combustion controls. The BACT/LAER Clearinghouse documents do not list any post-combustion particulate matter control technologies being used on combustion turbines. Consistent with the previous determinations as referenced by the State of Florida, such as the FPL West County, FMPA Treasure Coast, FPL Turkey Point, FPL Martin, FPL Manatee, FPL Fort Myers, Santa Rosa and the City of Tallahassee projects, the use of combustion controls and natural gas (low sulfur fuel) is considered BACT for particulate matter and is proposed for GEC Unit 1 and Unit 2. Limited operation while firing ultra-low sulfur fuel oil and natural gas in the combustion turbines is considered BACT.

6.0 GEC Unit 1 and Unit 2 H_2SO_4 BACT Analysis

The objective of this analysis was to determine BACT for sulfuric acid mist (H_2SO_4) emissions from GEC Unit 1 and Unit 2.

Emissions of H_2SO_4 can be controlled by limiting sulfur content in the fuel. The natural gas and ULSFO to be utilized for GEC Unit 1 and Unit 2 will contain less than 2 grains per 100 standard cubic feet and 0.0015 percent sulfur by weight, respectively. The selection of low sulfur fuel (both natural gas and ULSFO) provides inherently low SO_2 emissions, thus controlling the formation of sulfuric acid mist. In addition, no supplemental SO_3 emission controls, such as FGD systems or H_2SO_4 abatement systems, have been imposed on natural gas fired or low sulfur fuel oil fired combustion turbines by regulatory agencies.

Therefore, BACT for GEC Unit 1 and Unit 2 is the use of good combustion controls while firing natural gas or ULSFO with less than 0.0015 percent sulfur by weight. The basis of this determination is firing natural gas and ULSFO on the limitation on hours of operation as previously stated.

7.0 GEC Emergency Diesel Engine Generator and Emergency Diesel Fire Pump BACT Analysis

In the event of the loss of normal auxiliary power, ac power will be supplied by a new 1,500 kW, ULSFO fired emergency diesel engine generator. Additionally, a new emergency diesel fire pump will supply emergency fire water to the Project using 350 bhp diesel engine. The emergency diesel engine generator and the emergency diesel fire pump are exempt units as explained in Appendix A, Attachment 5 of this document. Because of their infrequent operation, and status as emergency equipment, the installation of post-combustion emission controls such as SCR and SNCR for NO_x, or FGD systems for SO_2, or oxidation catalyst for CO, while technically feasible for emergency generators and fire pumps, are far from cost-effective as control devices and are therefore not practical as BACT control alternatives. As such, JEA has determined that BACT for the emergency generator and fire pump is limited operation and good combustion controls while firing ULSFO. The proposed BACT determinations have no adverse environmental or energy impacts and are summarized below for each pollutant.

7.1 Select SO_2 BACT

The emergency generator and fire pump will emit small quantities of SO_2 as a result of the oxidation of sulfur in the fuel. A review of the informational databases discussed in Section 2.1 indicate that ULSFO is the most stringent permitted control for similar types of units operated in the manner proposed. No post-combustion FGD system has ever been applied to a generator/fire pump this small that is firing ULSFO. Therefore, ULSFO is proposed as the BACT. The BACT control is good combustion control and ULSFO.

7.2 Select NO_x BACT

Further review of the informational databases discussed in Section 2.1 indicated that emergency generators and fire pumps have not been required to install additional NO_x controls because their operation is of an intermittent nature. As discussed in Subsection 2.1.1.2, the engines must meet the applicable NSPS, which will apply depending on the year of engine manufacture. The BACT control is good combustion control.

7.3 Select PM/PM_{10} BACT

The emergency generator and fire pump will emit small quantities of particulates consisting of ash in the fuel and residual carbon and hydrocarbons caused from incomplete combustion. A review of the informational databases discussed in Section 2.1 indicated that good combustion control was the most stringent control permitted for similar units. Therefore, because of the very low operating hours of the emergency generator and fire pump, good combustion control and engine design are proposed as BACT.

As discussed in Subsection 2.1.1.2, the engines must meet the applicable NSPS, which will depend on the year of engine manufacture. The BACT control is good combustion control.

7.4 Select CO BACT

The control technologies for CO emissions evaluated for use on the emergency generator and fire pump are catalytic oxidation and proper design to minimize emissions. Because of the intermittent operation and low emissions, add-on controls would be prohibitively expensive. Thus, good combustion control is proposed as BACT for controlling the CO emissions from the emergency generator.

As discussed in Subsection 2.1.1.2, the engines must meet the NSPS that will apply, depending on the year of engine manufacture. The BACT control is good combustion control.

7.5 Select H_2SO_4 BACT

The emergency generator and fire pump will emit small quantities H_2SO_2 as a result of the oxidation of SO_2 in the exhaust. A review of the informational databases discussed in Section 2.1 indicated that ULSFO was the most stringent permitted control for similar types of units. Therefore, ULSFO is proposed as BACT. The BACT control is good combustion control and ULSFO.

8.0 GEC Natural Gas Fired Fuel Gas Heater

The fuel gas heater receives high-pressure natural gas from a single interface point for the natural gas supply system. As the natural gas is extracted from the high pressure pipeline across a pressure reducing control valve, the reduction in pressure will naturally cool the gas below the dew point temperature and to a temperature too low to be combusted in the boilers. As such, a natural gas fired fuel gas heater will be used to heat the natural gas upstream of the pressure reducing device to prevent the gas from dropping below the recommended operating temperature. The fuel gas heater will have a maximum heat input limit of 5.84 MBtu/h and designed for continuous operation. Because of its small size, the installation of post-combustion emission controls, such as SCR and SNCR for NO_x, or FGD systems for SO_2, or oxidation catalyst for CO, while technically feasible for the gate state heater, are far from cost-effective as control devices and are therefore not practical as BACT control alternatives. As such, JEA has determined that BACT for the fuel gas heater, which is similar to a process heater, is good combustion controls while firing low sulfur pipeline natural gas. The proposed BACT has no adverse environmental or energy impacts.

Attachment 1
NO_x Control Technology Review List

NO_X Top Down RBLC Clearinghouse Review Results
Table A1-1

FACILITY/COMPANY	STATE	FUEL	New (MW)	# of SCCTs	Turbine Model	LIMIT (LB/MBTU)	AVG PERIOD	CONTROL TECHNOLOGY	STATUS	COMMENTS	DATA SOURCE
Exxon Mobil Production Co., Exxon Mobile Bay - Northwest Gulf Field	AL	NG	15	2	Solar Taurus	25 ppm		SOLO NO_X	02/01/2005	1 CT on each of 2 Offshore Platforms (SOLO NOx Combustor)	RBLC/EPA Regions 4 and 7 CT Spreadsheet
Platte River Power Authority/Rawhide (82 MW)	CO	NG	82	1	GE Frame 7EA	Standard: 9 ppm; Startup/Shutdown: 100 ppm	daily	DLN	10/03/2003	Unit "D" CO PTE below significance level to avoid BACT: characterized as peaking plant, but not restricted in operating hours	EPA Regions 4 and 7 CT Spreadsheet
Florida Power & Light, FPL Manatee Plant - Unit 3	FL	NG	680	4	GE 7FA (170 MW)	Standard: 9 ppm; Power Augmentation: 12 ppm; Peaking: 15 ppm	24-hr	DLN	04/15/2003	Emission rates differ for modes of operation (duct burning, peaking, power augmentation)	RBLC/EPA Regions 4 and 7 CT Spreadsheet
City of Tallahassee - Arvah B. Hopkins Generating Station	FL	NG; FO	100	2	GE LM6000	NG and FO: 5 ppm	24-hr	SCR, WI	10/26/2004	Hours of operation is 5,840 during any consecutive 12-month period (4,000 hours may be on FO)	RBLC/EPA Regions 4 and 7 CT Spreadsheet
Keys Energy Services - Stock Island Power Plant	FL	FO	48	1	GE LM6000	42 ppm	24-hr	WI	09/12/2005	For operation greater than 2,500 hrs in a 12 month period requires installation of SCR	RBLC/EPA Regions 4 and 7 CT Spreadsheet
Tampa Electric Company - TEC/Polk Power Energy Station	FL	NG	330 (165 MW each)	2		9 ppm		DLN	4/28/2006		RBLC
Oleander Power Project, L.P. - Unit 5	FL	NG; FO	190	1	GE 7FA (190 MW)	NG: 9 ppm (24-hr rolling avg); FO: 42 ppm (4-hr rolling avg)	24-hr rolling avg / 4 hr rolling avg	NG: DLN; FO: WI	11/17/2006	Back-up fuel oil use is limited to 500 hours per year.	FDEP NSR/PSD Permits
Kansas City, Kansas Board of Public Utilities - Nearman Creek Station	KS	NG; FO	80	1	1 - GE-7EA	NG: 9 ppm; FO: 42 ppm	30-day rolling	DLN, WI	10/18/2005		RBLC/EPA Regions 4 and 7 CT Spreadsheet
Creole Trail LNG, LP - Creole Trail LNG Terminal	LA	NG	120 (30 MW each)	4		25 ppm		DLN	12/11/2007		RBLC
Mirant Mid-Atlantic, LLC - Chalk Point	MD	NG; FO	340 (85 MW each)	4	GE 7EA	NG: 9 ppm; FO: 42 ppm	3-hr	NG: DLN; FO: WI	4/12/2005	Project to be operated in simple cycle mode only.	RBLC
MN Municipal Power Agency - Fairbault Energy Park	MN	NG; FO	340 (170 MW each)	2	Mit 501F	NG: 25 ppm; FO: 42 ppm	3-hr	DLN	7/15/2004	Initial operation in simple cycle mode and conversion to CCCT in the future.	RBLC
South Mississippi Electric Power Assn. - Moselle Plant	MS	NG	84	1	GE 7EA (83.5 MW)	9 ppm	3-hr	DLN with Inlet Gas Cooling	12/10/2004	Hot SCR - $9,973/ton NOx; CatOx - $2,417/ton CO	RBLC/EPA Regions 4 and 7 CT Spreadsheet
TVA - Kemper Combustion Plant	MS	FO	320 (80 MW each)	4		42 ppm		WI	1/25/2005		RBLC
Aquila Merchant - South Harper Peaking Facility	MO	NG	341	3	SW 501D5A (113 MWe each)	15 ppm@15%O2		DLN	10/10/2006	Each turbine limited to 2,500 hours of operation per year; entire plant limited to 4,000 hours per year.	EPA Regions 4 and 7 CT Spreadsheet
Omaha Public Power - Cass County Power Plant	NE	NG	340 (170 MW each)	2		NG: 20 ppm		DLN	6/22/2004		RBLC
Rolling Hills Generating, LLC - Rolling Hills Generating Plant	OH	NG	1,045	5	SW 501F	15 ppm		DLN	01/17/2006	Peaking Power Station	RBLC/EPA Regions 4 and 7 CT Spreadsheet
First Energy, Ohio Edison - West Larain Plant	OH	NG; FO	425	5		NG: 9 ppm; FO: 42 ppm	NG: 12-month r.avg.; FO: 1-hr	NG: DLN, FO: WI	11/17/2004	NG: Restricted on 5,431 hrs / CT; FO: 1,873,239 gallons on all 5 CTs	RBLC/EPA Regions 4 and 7 CT Spreadsheet
Cinergy - PSI Energy, Madison Station	OH	NG; FO	677 (85 MW each)	8	GE 7EA	NG: 15 ppm; FO: 42 ppm	1-hr	DLN	8/24/2004		RBLC
Rolling Hills Generating, LLC - Rolling Hills Generating Plant	OH	NG	1,045	5	SW 501F	15 ppm		DLN	01/17/2006	The hours of operation of the 5 SC were increased from 2,000 hrs/yr to 4,000 hrs/yr.	RBLC/EPA Regions 4 and 7 CT Spreadsheet

NO_X Top Down RBLC Clearinghouse Review Results
Table A1-1

FACILITY	STATE	FUEL	New (MW)	# of SCCTs	Turbine Model	LIMIT (LB/MBTU)	AVG PERIOD	CONTROL TECHNOLOGY	STATUS	COMMENTS	DATA SOURCE
Mustang Power, LLC - Harrah	OK	NG				25 ppm		SCR	02/13/2002		RBLC/EPA Regions 4 and 7 CT Spreadsheet
Mustang Power, LLC - Horseshoe Energy Project	OK	NG	180	4	LM6000	12.5 ppm		SCR	02/12/2002	Each CT is limited to a maximum operation 3,504 hrs/yr	RBLC/EPA Regions 4 and 7 CT Spreadsheet
Public Service Co. of Oklahoma, PSO Riverside Jenks Power St.	OK	NG		1		9 ppm		DLN	3/22/2007		RBLC
Broad River Energy Center (f/k/a Cherokee Falls)	SC	NG, FO	340	2	GE 7FA (170 MW)	9 ppm (12 ppm w/PA); 42 ppm FO		DLN	05/22/2003	Hot SCR - $22,800/ton NOx; CatOx - $10,500/ton CO	RBLC/EPA Regions 4 and 7 CT Spreadsheet
Santee Cooper - Rainey Generating Station	SC	NG	251	3	GE 7EA (83.5 MW)	9 ppm		DLN	05/08/2003	Hot SCR - $15,550/ton NOx; CatOx - $1,717/ton CO	RBLC/EPA Regions 4 and 7 CT Spreadsheet
So. Tx. Elec COOP - Sam Rayburn Generating Station	TX	NG; FO	180	3	LM6000	5 ppm (except for Startup/Shutdown)		SCR	01/17/2002	FO is limited to 720 hrs/yr (FO to be utilized only as backup)	RBLC/EPA Regions 4 and 7 CT Spreadsheet
Exxon Mobil Corp. - Exxon Mobil Chemical Baytown Olefins Plant	TX		170	1	F7FA	3		SCR	06/13/2003		RBLC/EPA Regions 4 and 7 CT Spreadsheet
City of Bryan	TX		50	1	LM6000	5		SCR	03/28/2003		EPA Regions 4 and 7 CT Spreadsheet
Brownsville Public Utility	TX		50	1	LM6000	5		SCR	09/08/2003		EPA Regions 4 and 7 CT Spreadsheet
Brownsville Public Utility	TX		50	1	LM6000	5		SCR	09/12/2003		EPA Regions 4 and 7 CT Spreadsheet
Pacificorp - Gadsby	UT	NG	131	3	GE LM6000 PC Sprint	5 ppm	30 DRA	WI & SCR	04/03/2002	Turbines are at existing power plant consisting of three NG boilers in mod PM10 N/A area. NOx limit is PSD BACT and LAER.	EPA Regions 4 and 7 CT Spreadsheet
Pacificorp - Currant Creek Power Project	UT	NG	1,050	2	GE 7FA	Standard: 9.0 ppm; Transient Load Conditions: 25 ppm	18-hr	DLN	05/17/2004	Project scaled back from 4 turbines to 2 turbines based on impacts to nonattainment area nearby.	EPA Regions 4 and 7 CT Spreadsheet
VIWAPA-St Thomas	VI	FO	39	1	GE Frame 6	42 ppm		WI	10/21/2004		RBLC/EPA Regions 4 and 7 CT Spreadsheet
Buchanan Generation, LLC Allegheny Energy Supply	VA	NG	100	2	LM 6000	25 ppm		WI	01/31/2002		RBLC/EPA Regions 4 and 7 CT Spreadsheet
Dynegy Marketing and Trade, Chickahominy Power	VA	NG; FO	675	4	Siemens 501F	15.0 ppm NG, 42 ppm FO		LNB - NG, WI - FO	01/10/2003	Max. operating hours < 1,200 hrs/month firing FO and < 2,350 hrs/month firing NG; Only NG during April - October	RBLC/EPA Regions 4 and 7 CT Spreadsheet
Old Dominion Electric Cooperative - Louisa Facility	VA	NG	600	5	GE 7EA	NG: 10.5 ppm / 9 ppm; FO: 42 ppm	NG: 1-hr / 30-day; FO: 1-hr	NG: DLN; FO: WI	03/11/2003		RBLC/EPA Regions 4 and 7 CT Spreadsheet
Cinergy Capital & Trading - Cincap Martinsville	VA	NG	330	4	GE 7EA	9 ppm		DLN	01/08/2003		RBLC/EPA Regions 4 and 7 CT Spreadsheet
White Oak Power Company, LLC	VA	NG; FO	680	4	GE 7 FA	NG: 9 ppm; FO: 50 ppm		LNB	08/29/2002		RBLC/EPA Regions 4 and 7 CT Spreadsheet
Puget Sound Energy - Fredonia	WA	NG; FO	110	2	2 - Pratt & Whitney FT8 (Twin Pack)	5.0 ppm	3-hr	SCR	07/16/2003	Ecology - TIES. NWAPA. Mt Vernon, WA. ORIS 607.	EPA Regions 4 and 7 CT Spreadsheet
Wisconsin Electric Power - WE Energies Concord	WI	NG; FO	100	1		NG: 25 ppm; FO: 65 ppm		WI	11/29/2006	BACT; SCR rejected at $10,257/ton; Ox Cat rejected at $5984/ton incremental cost	RBLC/EPA Regions 4 and 7 CT Spreadsheet
Wisconsin Electric Power - WE Energies Power	WI	NG	100	1		25 ppm		DLN, WI	1/26/2006		RBLC

Sources:

EPA Regions 4 and 7 CT Spreadsheet -- Data from EPA Regions 4 and 7 Combustion Turbine Spreadsheet
RBLC -- Data from EPA's RBLC Clearinghouse
FDEP NSR/PSD Permits -- Data from Florida Department of Environmental Protection NSR/PSD Construction Permits Website (Power Plants)

Attachment 2
CO Control Technology Review List

CO Top Down RBLC Clearinghouse Review Results
Table A2-1

FACILITY/COMPANY	STATE	FUEL	New (MW)	# of SCCTs	Turbine Model	LIMIT (LB/MBTU)	AVG PERIOD	CONTROL TECHNOLOGY	STATUS	COMMENTS	DATA SOURCE
Exxon Mobil Production Co., Exxon Mobile Bay - Northwest Gulf Field	AL	NG	15	2	Solar Taurus	50 ppm		GCP	02/01/2005	1 CT on each of 2 Offshore Platforms (SOLO NOx Combustor)	RBLC/EPA Regions 4 and 7 CT Spreadsheet
Platte River Power Authority/Rawhide (82 MW)	CO	NG	82	1	GE Frame 7EA	<100 tpy	N/A	GCP	10/03/2003	Unit "D" CO PTE below significance level to avoid BACT; characterized as peaking plant, but not restricted in operating hours	EPA Regions 4 and 7 CT Spreadsheet
Florida Power & Light, FPL Manatee Plant - Unit 3	FL	NG	680	4	GE 7FA (170 MW)	Standard: 8 ppm; Power Augmentation: 12 ppm	24-hr	GCP	04/15/2003	Emission rates differ for modes of operation (duct burning, peaking, power augmentation)	RBLC/EPA Regions 4 and 7 CT Spreadsheet
City of Tallahassee - Arvah B. Hopkins Generating Station	FL	NG; FO	100	2	GE LM6000	NG and FO: 6 ppm		CatOX	10/26/2004	Hours of operation is 5,840 during any consecutive 12-month period (4,000 hours may be on FO)	RBLC/EPA Regions 4 and 7 CT Spreadsheet
Keys Energy Services - Stock Island Power Plant	FL	FO	48	1	GE LM6000	30 ppm		GCP	09/12/2005	For operation greater than 2,500 hrs in a 12 month period requires installation of SCR	RBLC/EPA Regions 4 and 7 CT Spreadsheet
Kansas City, Kansas Board of Public Utilities - Nearman Creek Station	KS	NG; FO	80	1	1 - GE-7EA	NG: 25 ppm; FO: 20 ppm	30-day rolling	GCP	10/18/2005		RBLC/EPA Regions 4 and 7 CT Spreadsheet
Creole Trail LNG, LP - Creole Trail LNG Terminal	LA	NG	120 (30 MW each)	4		25 ppm		GCP	12/11/2007		RBLC
Mirant Mid-Atlantic, LLC - Chalk Point	MD	NG; FO	340 (85 MW each)	4	GE 7EA	NG: 25 ppm; FO: 20 ppm	3-hr	GCP	4/12/2005	Project to be operated in simple cycle mode only.	RBLC
MN Municipal Power Agency - Fairbault Energy Park	MN	NG; FO	340 (170 MW each)	2	Mit 501F	NG and FO: 10 ppm	3-hr	GCP	7/15/2004	Initial operation in simple cycle mode and conversion to CCCT in the future.	RBLC
South Mississippi Electric Power Assn. - Moselle Plant	MS	NG	84	1	GE 7EA (83.5 MW)	20 ppm	3-hr	GCP	12/10/2004	Hot SCR - $9,973/ton NOx; CatOx - $2,417/ton CO	RBLC/EPA Regions 4 and 7 CT Spreadsheet
TVA - Kemper Combustion Plant	MS	FO	320 (80 MW each)	4		20 ppm		GCP	1/25/2005		RBLC
Aquila Merchant - South Harper Peaking Facility	MO	NG	341	3	SW 501D5A (113 MWe, each)	25 ppm	1-hr	GCP	10/10/2006	Each turbine limited to 2,500 hours of operation per year; entire plant limited to 4,000 hours per year.	EPA Regions 4 and 7 CT Spreadsheet
Omaha Public Power - Cass County Power Plant	NE	NG	340 (170 MW each)	2		15 ppm		GCP	6/22/2004		RBLC
Rolling Hills Generating, LLC - Rolling Hills Generating Plant	OH	NG	1,045	5	SW 501F	119 lb/hr (except during startup/shutdown)		GCP	01/17/2006	Peaking Power Station	RBLC/EPA Regions 4 and 7 CT Spreadsheet
First Energy, Ohio Edison - West Larain Plant	OH	NG; FO	425	5		83 lb/hr			11/17/2004	NG: Restricted on 5,431 hrs / CT; FO: 1,873,239 gallons on all 5 CTs	RBLC/EPA Regions 4 and 7 CT Spreadsheet
Rolling Hills Generating, LLC - Rolling Hills Generating Plant	OH	NG	1,045	5	SW 501F	119 lb/hr (except during startup/shutdown)		GCP	01/17/2006	The hours of operation of the 5 SC were increased from 2,000 hrs/yr to 4,000 hrs/yr.	RBLC/EPA Regions 4 and 7 CT Spreadsheet
Cinergy - PSI Energy, Madison Station	OH	NG; FO	677 (85 MW each)	8	GE 7EA	54 lb/hr		GCP	8/24/2004		RBLC

CO Top Down RBLC Clearinghouse Review Results
Table A2-1

FACILITY	STATE	FUEL	New (MW)	# of SCCTs	Turbine Model	LIMIT (LB/MBTU)	AVG PERIOD	CONTROL TECHNOLOGY	STATUS	COMMENTS	DATA SOURCE
Mustang Power, LLC - Harrah	OK	NG				40 ppm		GCP	02/13/2002		RBLC/EPA Regions 4 and 7 CT Spreadsheet
Mustang Power, LLC - Horseshoe Energy Project	OK	NG	180	4	LM6000	40 ppm		GCP	02/12/2002	Each CT is limited to a maximum operation 3,504 hrs/yr	RBLC/EPA Regions 4 and 7 CT Spreadsheet
Public Service Co. of Oklahoma, PSO Riverside Jenks Power St.	OK	NG		1		59 lb/hr		GCP	3/22/2007		RBLC
Broad River Energy Center (f/k/a Cherokee Falls)	SC	NG, FO	340	2	GE 7FA (170 MW)	9 ppm (15 ppm w/PA); 20 ppm FO		GCP	05/22/2003	Hot SCR - $22,800/ton NOx: CatOx - $10,500/ton CO	RBLC/EPA Regions 4 and 7 CT Spreadsheet
Santee Cooper - Rainey Generating Station	SC	NG	251	3	GE 7EA (83.5 MW)	25 ppm		GCP	05/08/2003	Hot SCR - $15,550/ton NOx; CatOx - $1,717/ton CO	RBLC/EPA Regions 4 and 7 CT Spreadsheet
So. Tx. Elec COOP - Sam Rayburn Generating Station	TX	NG; FO	180	3	LM6000	15 ppm		CatOX	01/17/2002	FO is limited to 720 hrs/yr (FO to be utilized only as backup)	RBLC/EPA Regions 4 and 7 CT Spreadsheet
Exxon Mobil Corp. - Exxon Mobil Chemical Baytown Olefins Plant	TX		170	1	F7FA	7.4			06/13/2003		RBLC/EPA Regions 4 and 7 CT Spreadsheet
City of Bryan	TX		50	1	LM6000	32			03/28/2003		EPA Regions 4 and 7 CT Spreadsheet
Brownsville Public Utility	TX		50	1	LM6000	32			09/08/2003		EPA Regions 4 and 7 CT Spreadsheet
Brownsville Public Utility	TX		50	1	LM6000	32			09/12/2003		EPA Regions 4 and 7 CT Spreadsheet
Pacificorp - Gadsby	UT	NG	131	3	GE LM6000 PC Sprint	10 ppm	8-HR BLOCK; ERR	Oxid Cat	04/03/2002	Turbines are at existing power plant consisting of three NG boilers in mod PM10 N/A area. NOx limit is PSD BACT and LAER.	EPA Regions 4 and 7 CT Spreadsheet
Pacificorp - Currant Creek Power Project	UT	NG	1,050	2	GE 7FA	7.8 ppm	24-hr	Oxid Cat	05/17/2004	Project scaled back from 4 turbines to 2 turbines based on impacts to nonattainment area nearby.	EPA Regions 4 and 7 CT Spreadsheet
Buchanan Generation, LLC Alleghency Energy Supply	VA	NG	100	2	LM 6000	53 ppm		GCP	01/31/2002		RBLC/EPA Regions 4 and 7 CT Spreadsheet
Dynegy Marketing and Trade, Chickahominy Power	VA	NG; FO	675	4	Siemens 501F	15 ppm NG, 50 ppm FO		GCP	01/10/2003	Max. operating hours < 1,200 hrs/month firing FO and < 2,350 hrs/month firing NG; Only NG during April - October	RBLC/EPA Regions 4 and 7 CT Spreadsheet
Old Dominion Electric Cooperative - Louisa Facility	VA	NG	600	5	GE 7EA	NG: 9 ppm; FO: 20 ppm	NG and FO: 3-hr	GCP	03/11/2003		RBLC/EPA Regions 4 and 7 CT Spreadsheet
Cinergy Capital & Trading - Cincap Martinsville	VA	NG	330	4	GE 7EA	25 ppm		GCP	01/08/2003		RBLC/EPA Regions 4 and 7 CT Spreadsheet
White Oak Power Company, LLC	VA	NG; FO	680	4	GE 7 FA	NG: 8 ppm; FO: 20 ppm		GCP	08/29/2002		RBLC/EPA Regions 4 and 7 CT Spreadsheet
Puget Sound Energy - Fredonia	WA	NG; FO	110	2	2 - Pratt & Whitney FT8 (Twin Pack)	Minor NSR		CatOx	07/16/2003	Ecology - TIES. NWAPA. Mt Vernon, WA. ORIS 607.	EPA Regions 4 and 7 CT Spreadsheet
Wisconsin Electric Power - WE Energies Concord	WI	NG; FO	100	1		NG: 20 lb/hr (>= 75% Max. Output), 30 lb/hr (> 75% Max. Output)			11/29/2006	BACT; SCR rejected at $10,257/ton; Ox Cat rejected at $5984/ton incremental cost	RBLC/EPA Regions 4 and 7 CT Spreadsheet
Wisconsin Electric Power - WE Energies Power	WI	NG	100	1		20 lb/hr (operate at 75% Max. Output or higher)		GCP	1/26/2006		RBLC

Sources:

EPA Regions 4 and 7 CT Spreadsheet -- Data from EPA Regions 4 and 7 Combustion Turbine Spreadsheet
RBLC -- Data from EPA's RBLC Clearinghouse

Appendix E
Air Dispersion Modeling Protocol

Southeast Generating Station
Simple Cycle Combustion Turbine Facility

Air Dispersion Modeling Protocol

FEBRUARY, 2008

Prepared for:
JEA
Jacksonville, Florida

Prepared by:
Black & Veatch
Overland Park, Kansas

Building a world of difference.

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1.0 Introduction

JEA is proposing to install two combustion turbines (CTs) and associated support facility (hereinafter referred to as the Project) at the new Southeast Generating Station site (SEGS), in southeastern Duval County, Florida. The new units will be General Electric (GE) 7FA simple cycle CTs (CT1 & CT2), each operating at a nominal rating of 176 MW when firing with natural gas and a nominal rating of 190 MW when firing with ultra low sulfur fuel oil firing. New major support facilities include a diesel engine driven fire pump, a safe shutdown generator, a natural gas fired liquefied natural gas heater, and two approximately 2,000,000 gallon fuel oil storage tanks.

JEA anticipates that the potential emissions of the Project will not trigger air permitting review requirements under the Prevention of Significant Deterioration (PSD) program of Florida Regulation 62-212.400. However, during initial discussions with the Florida Department of Environmental Protection (FDEP), the FDEP requested that JEA consider the combined cycle combustion turbine (CCCT) project when determining the applicability to the PSD requirements. As such, JEA anticipates that the potential emissions of the CCCT project will trigger air permitting review requirements under the PSD.

This Ambient Air Quality Impact Analysis Protocol (hereinafter referred to as the Protocol) describes the air quality impact analysis methodology for obtaining a Construction Permit for the proposed simple cycle project under the PSD review program. After Florida Department of Environmental Protection (FDEP) review and approval, this Protocol will provide the basis of a mutually agreed upon procedure for the final ambient air quality impact analysis in support of the air construction permit application meeting PSD review requirements.

This Protocol describes site and source characteristics, determination of pollutants applicable to the air quality review, and the analytical procedures that will be used to conduct the ambient air quality impact analysis (AAQIA). The construction permit application and supporting AAQIA will include a determination of compliance with the National Ambient Air Quality Standards (NAAQS), New Source Performance Standards (NSPS), the PSD increments, and an assessment of additional impacts.

2.0 Project Characterization

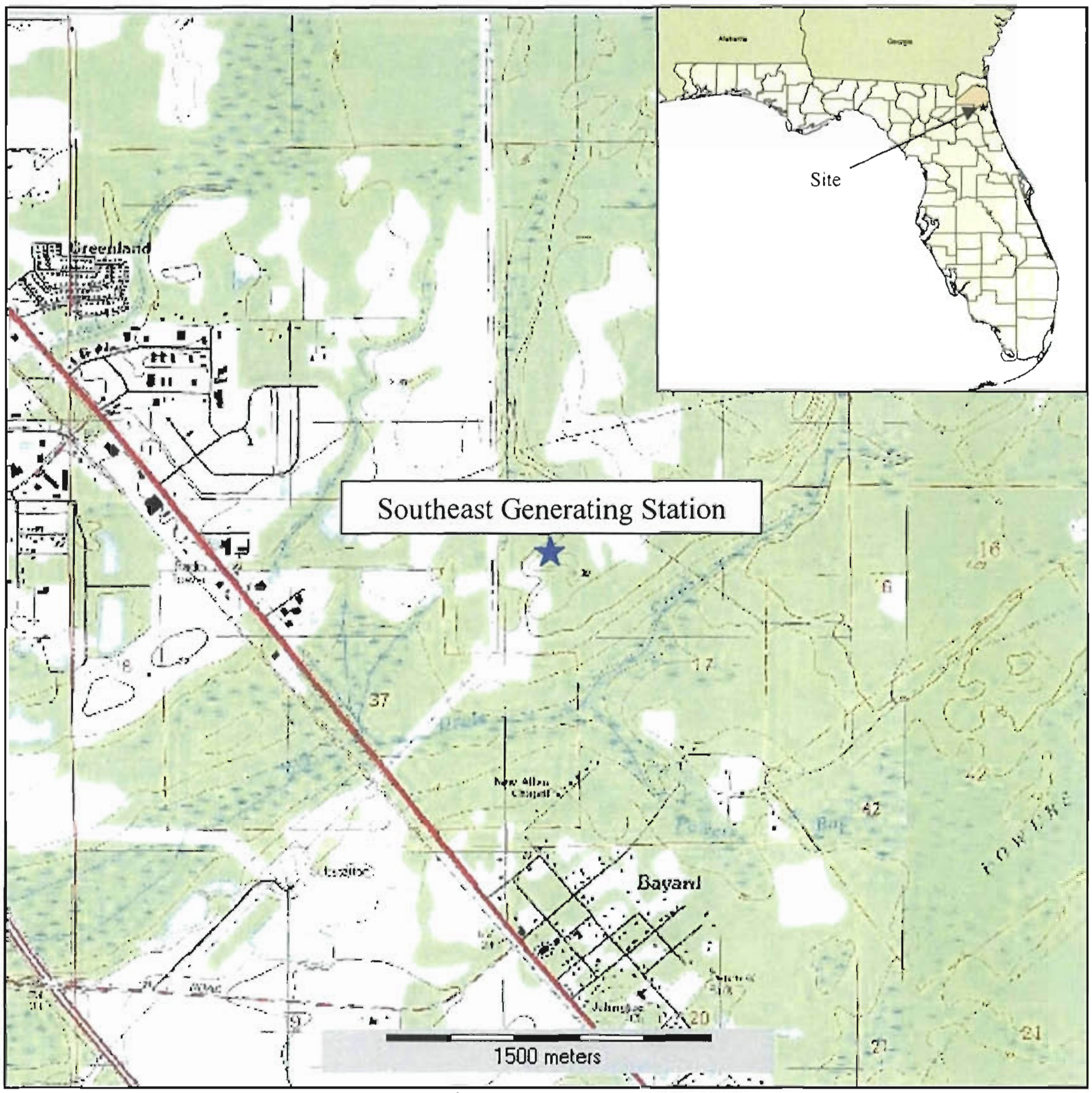
The following sections briefly characterize the Project including a general description of the facility, location, and potential emission units.

2.1 Project Location

The SEGS is located in southeastern part of Jacksonville. The specific location of the project is illustrated in Figure 2-1. The site location has a sub-tropical climate with hot summers and mild winters.

2.2 Project Description

JEA is proposing the installation of two new natural gas- or ultra low sulfur fuel oil-fired, GE 7FA simple cycle CTs (Units 1 & 2) at the new SEGS in Jacksonville, Florida. Units 1 & 2 will each have a nominal rating of 176 MW when firing with natural gas and a nominal rating of 190 MW when firing with ultra low sulfur fuel oil firing. New major support facilities include a diesel engine driven fire pump, a safe shutdown generator, a natural gas-fired liquefied natural gas heater, and two approximately 2,000,000 gallon fuel oil storage tanks.



USGS Topographic Maps, Palm Valley & Bayard; 1:100K

Figure 2-1
Proposed Project Location

2.3 Project Emissions

For the proposed Units 1 & 2 SCCT, emissions and stack parameters will be developed from performance data for unit loads of 100, 75, and 50 percent of maximum capacity over a range of representative ambient temperatures (7, 59, 69, and 105°F) for both natural gas and ultra low sulfur fuel oil firing. This range of temperatures represents the site minimum, ISO, site average, and site maximum temperatures, respectively. The emissions included in the air dispersion modeling analysis for Units 1 & 2 will be based on direct pound per hour emissions to the atmosphere.

Units 1 & 2 will have the capability of operating in several configurations; including firing natural gas or ultra low sulfur fuel oil, along with different unit loads and at different ambient temperatures. A process called enveloping may be used in the modeling. Enveloping allows multiple operating scenarios to be conservatively considered in an AAQIA, while keeping the actual air dispersion modeling runs to a minimum. However, it is possible that because of the specific characteristics of the source, this analysis approach could result in overly conservative modeling impacts. In this case, the AAQIA may be performed for each individual load and ambient temperature combination.

The emissions and stack parameters for each of the ancillary equipment will be based on manufacturer data and these emission sources will be included in the AAQIA.

3.0 Class I Ambient Air Quality Analysis

As part of the air impact evaluation for the new units at the SEGS site, analyses of the proposed project's effect on all Class I areas within 300 km will be performed. The Bradwell Bay Wilderness (BBW), Chassahowitzka Wilderness (CW), Okefenokee Wilderness (OW), St. Marks Wilderness (SMW), and Wolf Island Wilderness (WIW) areas are the Class I areas of concern for this project. Federal Class I areas are afforded special environmental protection through the use of Air Quality Related Values (AQRVs). The AQRVs of interest in this protocol are regional haze and deposition. Additionally, Class I Significant Impact Levels (SILs) will be evaluated and compared to the recommended thresholds. Figure 3-1 presents the location of the proposed project site with respect to the Class I areas.

The methodology of the refined CALPUFF analysis will closely follow those procedures recommended in the *Interagency Workgroup on Air Quality Modeling (IWAQM) Phase II* report dated December 1998 and the *Phase I Federal Land Managers' Air Quality Related Values Workgroup (FLAG)* report dated December 2000 where appropriate for model option selections. This protocol includes a discussion of the meteorological and geophysical databases to be used in the analysis, the preparation of those databases for introduction into the modeling system, and the air modeling approach to assess impacts at BBW, CW, OW, SMW, and WIW.

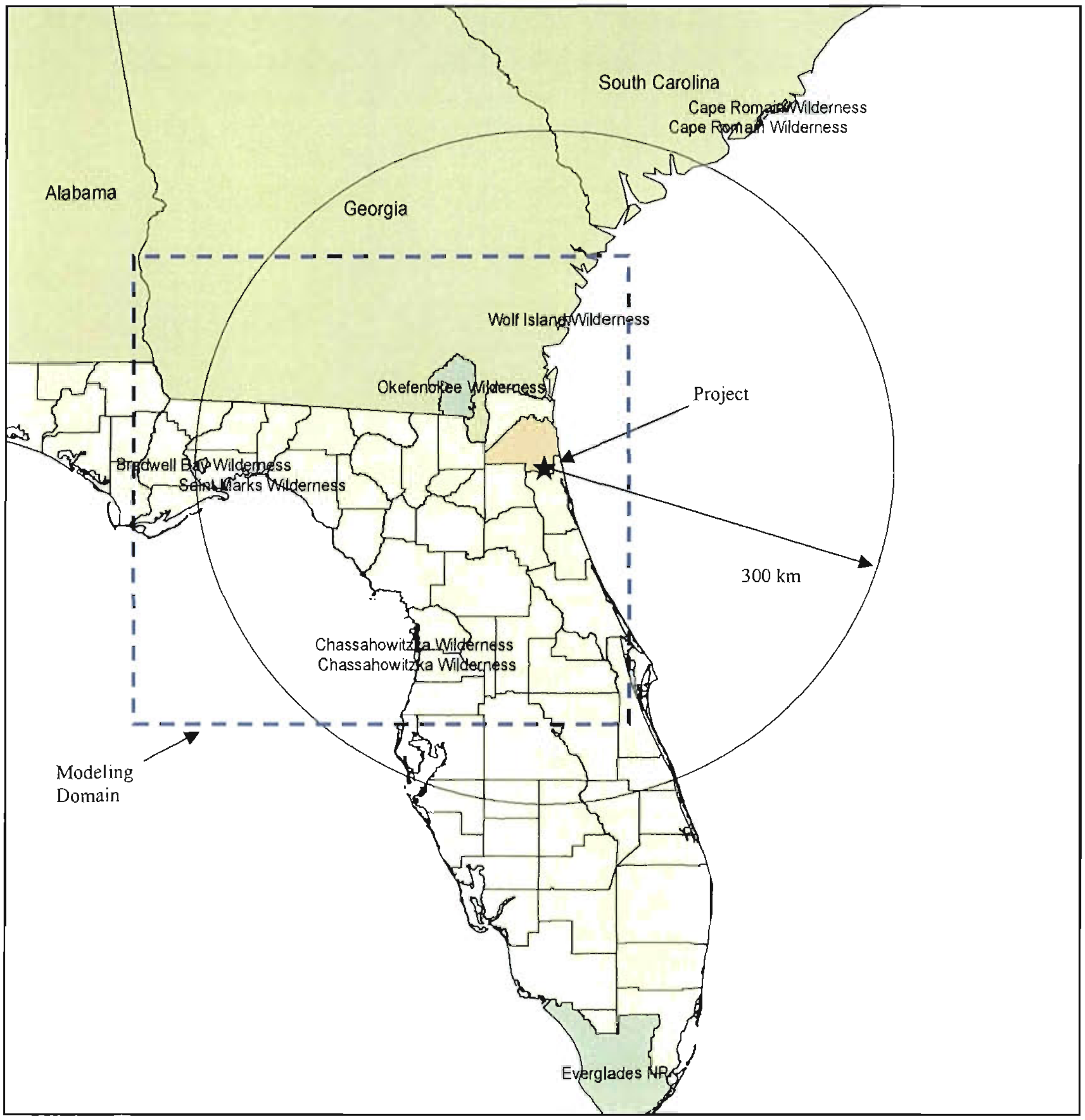


Figure 3-1
Proposed Project Location and Class I Areas

3.1 Class I Model Selection and Inputs

3.1.1 Model Selection

The California Puff (CALPUFF, Version 5.8, Level 070623) air modeling system will be used to model the proposed project and assess the AQRVs at the Class I areas. CALPUFF is a non-steady state Lagrangian Gaussian puff long-range transport model that includes algorithms for building downwash effects, as well as chemical transformations (important for visibility controlling pollutants), and wet/dry deposition. The CALMET model (Version 5.8, Level 070623), a preprocessor to CALPUFF, is a diagnostic meteorological model that produces three-dimensional fields of wind and temperature and two-dimensional fields of other meteorological parameters. CALMET was designed to process raw meteorological, terrain, and land-use databases to be used in the air modeling analysis. However, VISTAS, the Regional Planning Organization responsible for assisting with regional haze issues in the southeast, contracted Earth Tech to produce CALPUFF-ready, CALMET meteorological data files, thus bypassing the need to run the resources intensive CALMET processor for this modeling analysis. VISTAS has provided 2001-2003 CALMET files for five 4-km sub-regional domains as illustrated in Figure 3-2. The modeling proposed in this protocol will use the CALMET files prepared for sub-domain 2.

3.1.2 CALPUFF Model Settings

The CALPUFF settings contained in Table 3-1 will be used for the modeling analyses.

3.1.3 Project Emissions

The CALPUFF analysis will only include the emissions from Units 1 and 2. The worst-case representative stack parameters and pollutants emission rates at 100% operating load will be used in the CALPUFF analyses. Per guidance from NPS, the PM/PM_{10} emissions will be speciated based on size and composition and therefore be broken into the following constituents: elemental carbon (EC), organic carbon (OC), and soils (SOIL) for the regional haze analysis.

3.1.4 Building Wake Effects

The CALPUFF analysis will include the facility's building dimensions to account for the effects of building-induced downwash on the emission source. Dimensions for all significant building structures will be processed with the USEPA's Plume Rise Model Enhancement (PRIME) version of Building Profile Input Program (BPIPPRM, Version 04274).

3.1.5 Receptor Locations

The CALPUFF analyses will use an array of discrete receptors over the Class I areas, which were created and distributed by the National Park Service (NPS). Specifically, the array consists of receptors appropriately spaced to cover the extent of the Class I areas. Receptor elevations are included in the same NPS- provided receptor files.

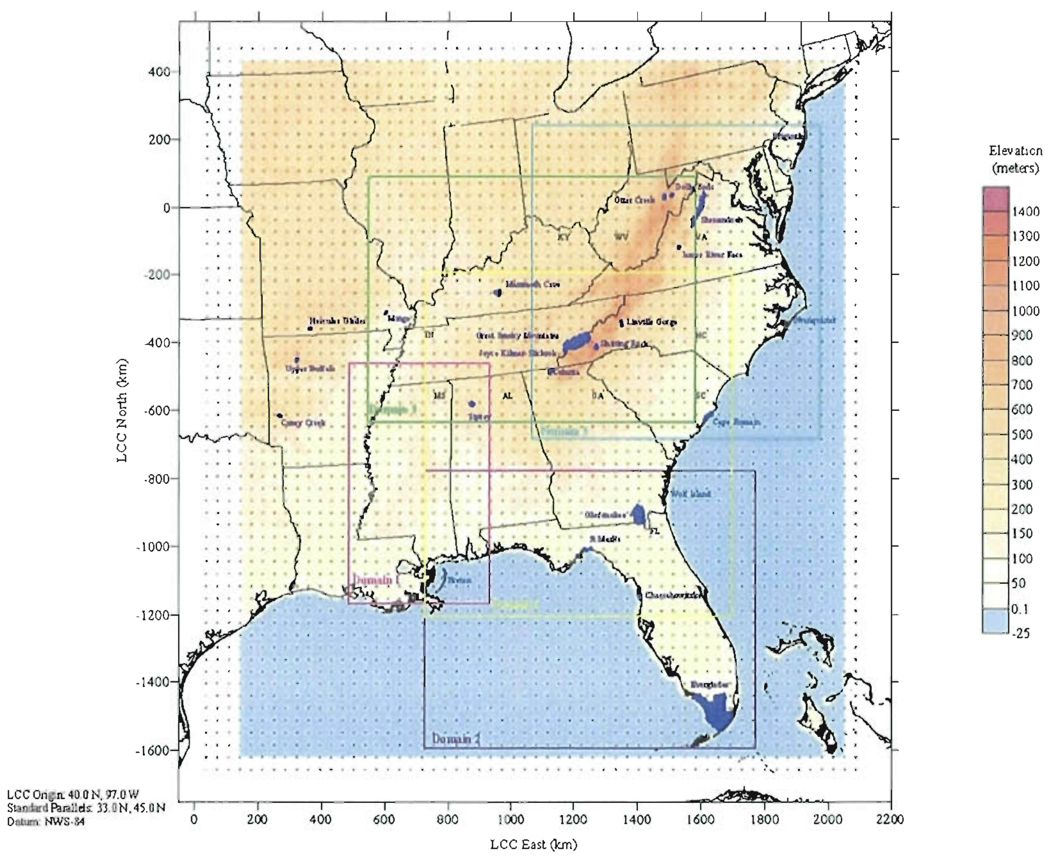


Figure 3-2
VISTAS 4-km CALMET Sub-Domains

Table 3-1
CALPUFF Model Settings

Parameter	Setting
Pollutant Species Emitted	SO_2, SO_4, NO_x, HNO_3, NO_3, and PM_{10}
Chemical Transformation	MESOPUFF II scheme
Deposition	Include both dry and wet deposition, plume depletion
Meteorological/Land Use Input	VISTAS CALMET Files
Plume Rise	Transitional plume rise, stack-tip downwash, partial plume penetration
Dispersion	Puff plume element, PG/MP coefficients, rural ISC mode, PRIME building downwash scheme
Terrain Effects	Partial plume path adjustment
Output	Create binary concentration and wet/dry deposition files including output species for all pollutants.
Model Processing	Regional Haze: Highest predicted 24-hour change as processed by CALPOST Class I SILS: Highest predicted concentrations at the applicable averaging periods for those pollutants that exceed the respective PSD Significant Emission Rates (SERs).
Background Values	Ammonia: 0.5 ppb (monthly); Ozone: Hourly ozone data files provided by TRC for use in VISTAS's BART modeling analyses will be utilized. A review of the CASTNET database will be performed to obtain monthly averages and these values will be substituted by the CALPUFF model should there be missing hourly values in the VISTAS ozone files.

3.1.6 Meteorological Data Processing

The refined 4-km grid resolution VISTAS CALMET files from sub-domain 2 will be used as the meteorological and geophysical data for input to CALPUFF. These high resolution, CALPUFF-ready, CALMET files were composed of available surface and upper air observations in addition to the highest resolution MM5 data available for each year (i.e., 12-km MM5 data for 2001 and 2002 and 36-km MM5 data for 2003). A 4-km grid resolution is expected to be adequate given the lack of significant terrain features in central Florida

The VISTAS 2001-2003 meteorological data was recently re-processed by the Fish & Wildlife Service (FWS) using the current EPA regulatory version of CALMET, i.e., Version 5.8 Level 070623. Black & Veatch obtained this re-processed fine-grid CALMET dataset for the entire VISTAS region from the North Carolina Department of Environment and Natural Resources.

3.1.6.1 CALMET Settings

The major features of CALMET used by Earth Tech to develop the CALMET files are listed below.

- Modeling period: 3 years (2001-2003)
- Meteorological inputs: MM5 data provide initial guess fields in CALMET. Meteorological observational data are used in the Step 2 calculations. Overwater (buoy) data were used in addition to the hourly surface meteorological observations, precipitation observations and twice-daily upper air sounding data.
- CALMET grid resolution: 4-km
- CALMET vertical layers: 10 layers. Cell face heights (meters): 0, 20, 40, 80, 160, 320, 640, 1200, 2000, 3000, 4000.
- CALMET mode: Refined mode with all available observational data included in the Step 2.
- Diagnostic options: IWAQM default values.
- CALMET options dealing with radius of influence parameters: R1 = 5 km, R2 = 5 km, RMAX1 = 40 km, RMAX2 = 40 km, RMAX3 = 100 km, BIAS(NZ) = 10*0, ICALM = 0.
- TERRAD (terrain scale) is required for runs with diagnostic terrain adjustments which was used for all years for the subregional domains. Value of 15 km was determined from testing and used in modeling.

- Land use defining water: JWAT1 = 55, JWAT2 = 55 (large bodies of water). This feature allows the temperature field over large bodies of water such as the Atlantic Ocean and the Great lakes to be properly characterized by buoy observations.
- Mixing height averaging parameter for the subregional simulations determined by TRC based on sensitivity tests was MNMDAV=1.
- Geophysical data for regional runs: 3 arc-second USGS DEM terrain data set (SRTM30 data also used as a backup in case when 3 arc-second data are missing), CTG USGS 200m land use dataset.
- References for these and other CALMET datasets can be found on the CALPUFF data page of the official CALPUFF site (www.src.com).

3.1.7 Modeling Domain

The CALPUFF modeling domain will be a subset of the previously discussed CALMET domain. The size of the domain used for the modeling will be based on the distances needed to cover the area from the proposed project to the receptors at the Class I areas with at least an 80 km buffer zone in each direction. The modeling analysis will be performed in the Lambert Conformal Conic (LCC) coordinate system with standard parallels of 33 and 45 degrees north latitude and reference latitude and longitude of 40 and 97 degrees, respectively. A rectangular modeling domain extending 412 km in the east-west (x) direction and 432 km in the north-south (y) direction will be used for the refined modeling analysis. The southwest corner of the domain is located at 1,137.995 km Easting and -1,206 km Northing (LCC, NWS-1984 coordinates). The grid resolution for the domain will be 4 km. A grid spacing of 4 km yields 103 grid cells in the x-direction and 108 grid cells in the y-direction. Figure 3-1 illustrates the size and location of the modeling domain.

3.2 CALPUFF Analyses

The preceding model inputs and settings for the CALPUFF modeling system will be used to complete the Class I analyses on the Class I areas, including regional haze and Class I SILs.

3.2.1 Regional Haze Analysis

A regional haze analysis will be performed for the Class I areas, for ammonium sulfates, ammonium nitrates, and particulate matter, by appropriately characterizing model predicted outputs of SO_4, NO_3, and PM_{10} concentrations. PM_{10} emissions will be speciated into filterable and condensable PM size categories using NPS speciation spreadsheets.

3.2.1.1 Visibility

Visibility is an AQRV for all Class I areas except BBW, as such, a visibility analysis will not be performed for BBW. Visibility can take the form of plume blight for nearby areas, or regional haze for long distances (e.g., distances beyond 50 km). Because the Class I areas lies beyond 50 km from the proposed project, the change in visibility is analyzed as regional haze. Regional haze impairs visibility in all directions over a large area by obscuring the clarity, color, texture, and form of what is seen. Current regional haze guidelines characterize a change in visibility by either of the following methods:

1. Change in the visual range, defined as the greatest distance that a large dark object can be seen, or
2. Change in the light-extinction coefficient (b_{ext}).

Visual range can be related to extinction with the following equation:

$$b_{ext}\,(Mm^{-1}) = 3912 / vr\,(Mm^{-1})$$

Visual range (vr) is a measure of how far away a large black object can be seen in the atmosphere under several severe assumptions including: an absolutely dark target, uniform lighting conditions (cloud free skies), uniform extinction in all directions, a limiting contrast discrimination level, a target high enough in elevation to account for earth curvature, and several other factors. Visual range is, at best, a limited concept that allows relatively simple comparisons between visual air quality levels and should not be thought of as the absolute distance that can be seen through the atmosphere.

The b_{ext} is the attenuation of light per unit distance due to the scattering (light reduced away from the site path) and absorption (light captured by aerosols and turned into heat energy) by gases and particles in the atmosphere. A change in the extinction coefficient produces a perceived visual change that is measured by a visibility index called the deciview. The deciview (dv) is defined as:

$$dv = 10 \ln (1 + b_{exts} / b_{extb})$$

where: b_{exts} is the extinction coefficient calculated for the source, and

b_{extb} is the background extinction coefficient

A uniform incremental change in b_{extb} or visual range does not necessarily result in uniform changes in perceived visual air quality. In fact, perceived changes in visibility are best related to a percent change in extinction. Based on NPS guidance, if the change in extinction is less than 5 percent, no further analysis is required. An index similar to the deciview that simply quantifies the percent change in visibility due to the operation of a source is calculated as:

$$\Delta\% = (b_{exts} / b_{extb}) \times 100$$

3.2.1.2 Background Visual Ranges and Relative Humidity Factors

The background visual range is based on data representative of historical conditions at the Class I areas. The background visual range, or constituents thereof, for each of the Class I areas will be obtained from the Phase I FLAG Report, December 2000. The average relative humidity factor for each day will be computed by determining the relative humidity factor for each hour's relative humidity for the 24-hour period that the impact occurred. This factor, based on each hour's relative humidity can be obtained by using Table 2.A-1 of Appendix 2.A of the Phase I FLAG Report. These factors (a relative humidity factor for each hour of relative humidity) will then be used to determine the average relative humidity factor for that day (24-hour period). All of this is accomplished with the use of the CALPOST post-processor.

3.2.1.3 Interagency Workgroup On Air Quality Modeling (IWAQM) Guidelines

The CALPUFF air modeling analysis will closely follow the recommendations contained in the *IWAQM Phase II Summary Report and Recommendations for Modeling Long Range Transport Impacts*, (EPA, 12/98) where appropriate. Table 3-2 summarizes the IWAQM Phase II recommendations. The methodology in Table 3-2 will be used to compute the results of the regional haze analysis. However, CALPOST now possesses the ability to post-process the modeling results specific to the regional haze analysis through the selection of one of seven modeling options. The post-processing selection will be made to calculate regional haze based on the appropriate available data/resources. Specifically, regional haze will be calculated using Method 2, which consists of computing extinctions from speciated PM measurements using hourly relative humidity adjustments for observed and modeled sulfate and nitrates. The relative humidity will be capped at 95 percent. Method 7, which eliminates hours during which visibility limiting weather events occur, may be explored as necessary. While this process occurs within CALPOST, a typical calculation methodology is illustrated below.

Table 3-2
Outline of IWAQM Refined Modeling Analyses Recommendations

Meteorology	Use CALMET (minimum 6 to 10 layers in the vertical; top layer must extend above the maximum mixing depth expected); horizontal domain extends 50 to 80 km beyond outer receptors and source being modeled; terrain elevation and land-use data is resolved for the situation.
Receptors	Within Class I area(s) of concern; NPS will provide the modeling receptors.
Dispersion	1. CALPUFF with default dispersion settings. 2. Use MESOPUFF II chemistry with wet and dry deposition. 3. Define background values for ozone and ammonia for area.
Processing	Use highest predicted 24-hr SO_4, PM_{10}, and NO_3 value; compute a day-average relative humidity factor (f(RH)) for the worst day for the predicted specie, calculate extinction coefficients and compute percent change in extinction using the FLAG supplied background extinction where appropriate. This can all now be accomplished with the use of Method 2 in the CALPOST post-processor.
Based on the *IWAQM Phase II Summary Report and Recommendations for Modeling Long Range Transport Impacts* (EPA, 12/98)	

Calculation

Refined impacts will be calculated as follows:

1. Obtain 24-hour SO_4, NO_3, and PM speciation (EC & OC) impacts, in units of micrograms per cubic meter ($\mu g/m^3$).
2. Convert the SO_4 impact to $(NH_4)_2SO_4$ by the following formula:
   $(NH_4)_2SO_4$ ($\mu g/m^3$) = SO_4 ($\mu g/m^3$) x molecular weight $(NH_4)_2SO_4$ / molecular weight SO_4
   $(NH_4)_2SO_4$ ($\mu g/m^3$) = SO_4 ($\mu g/m^3$) x 132/96 = SO_4 ($\mu g/m^3$) x 1.375
3. Convert the NO_3 impact to NH_4NO_3 by the following formula:
   NH_4NO_3 ($\mu g/m^3$) = NO_3 ($\mu g/m^3$) x molecular weight NH_4NO_3 / molecular weight NO_3
   NH_4NO_3 ($\mu g/m^3$) = NO_3 ($\mu g/m^3$) x 80/62 = NO_3 ($\mu g/m^3$) x 1.29
4. Compute b_{exts} (extinction coefficient calculated for the source) with the following formula:

$b_{exts} = 3[NH_4NO_3]f(RH) + 3[(NH_4)_2SO_4]f(RH) + 4[OC] + 10[EC] + 4[PMC] + 1[PMF]$

5. Compute b_{extb} (background extinction coefficient) using the background visual range (km) from the FLAG document with the following formula:

   $b_{extb} = 3.912$ / visual range (km)

6. Compute the change in extinction coefficients:

   in terms of deciviews:

   $dv = 10 \ln(1 + b_{exts} / b_{extb})$

   in terms of percent change of visibility:

   $\Delta\% = (b_{exts} / b_{extb}) \times 100$

Based on the predicted SO_4, NO_3, and speciated PM concentrations, the proposed project's emissions will be compared to a 5 percent change in light extinction of the background levels. This is equivalent to a change in deciview of 0.5.

3.2.2 Deposition Analyses

Deposition analyses will be performed for all applicable Class I areas for both total sulfur and total nitrogen. The analyses will follow those procedures and methodologies set forth in the IWAQM Phase II Report and the *Guide for Applying the USEPA Class I Screening Methodology with the CALPUFF Modeling System* document, developed by Earth Tech, Inc. (the model developers) in September 2001. This document is a guide for using the POSTUTIL processor to perform deposition analyses. Specifically, deposition analyses will be performed as follows:

1. Perform CALPUFF model runs using the specified options previously mentioned in Section 3.1 (including output of both dry and wet deposition).
2. Use POSTUTIL to combine the wet and dry flux output files from CALPUFF and scale the contributions of SO_2, SO_4, NO_x, NO_3, and HNO_3 such that total (i.e., wet and dry) nitrogen and total sulfur flux are contained in the same file. The POSTUTIL file is set up such that SO_2 and SO_4 contribute sulfur mass and SO_4, NO_x, HNO_3, and NO_3 contribute to the nitrogen mass.
3. Apply the appropriate scaling factors found in IWAQM Phase II Report (Section 3.3 Deposition Calculations) to the CALPOST runs to account for the conversion of grams to kilograms, square meters to hectares (ha), seconds to hours, and hours to a year. Thus, the CALPOST results are in kg/ha/yr.

The model-predicted results will be compared to the 0.01 kg/ha/year Deposition Analysis Threshold (DAT) developed jointly by the NPS and the U.S. Fish and Wildlife Service (FWS).

3.2.3 Class I Impact Analysis

Ground-level impacts (in $\mu g/m^3$) at each of the Class I areas will be calculated for the appropriate criteria pollutants subject to PSD for each applicable averaging period. The results of this analysis will be compared with the Class I Significant Impact Levels (SILs) calculated as 4 percent of the Class I Increment values. Should the model predicted impacts onto the Class I area exceed the Class I SILs, an appropriately derived inventory of PSD increment consuming sources will be developed through FDEP and modeled with the CALPUFF modeling system for comparison to the Class I Increment values.

4.0 Class II Ambient Air Quality Analysis

Air Dispersion Model:	AERMOD (Latest version)
Model Options:	USEPA recommended regulatory default options.
GEP & Downwash:	USEPA's Plume Rise Model Enhancement (PRIME) version of Building Profile Input Program (BPIPPRM, Version 04274) will be used to determine GEP stack height and direction specific building downwash parameters for each 10-degree azimuth direction for each stack. Structures associated with the new site will be included in the downwash analysis.
Receptor Grids:	A 10 km nested rectangular receptor grid consisting of 100 m spacing out to 1 km, 250 m spacing from 1 km to 2.5 km, 500 m spacing from 2.5 km to 5 km, and 1,000 m spacing from 5 km to 10 km. Fenceline receptors will be placed at 50 m intervals, and a 100 m fine grid will be placed at maximum impact locations.
Terrain Considerations:	Terrain elevations at receptors will be obtained from 7.5-minute United States Geological Survey (USGS) Digital Elevation Model (DEM) files. For applications involving elevated terrain, the user must now also input a hill height scale along with the receptor elevation. To facilitate the generation of hill height scales for AERMOD, a terrain preprocessor, called AERMAP, has been developed by USEPA. For each receptor AERMAP searches for the terrain height and location that has the greatest influence on dispersion. In order to calculate the hill height scale, the DEM array and domain boundary must include all terrain features that exceed a 10% elevation slope from any given receptor. A visual inspection of the surrounding DEM files will be performed to ensure all such terrain nodes are covered in the computation of the hill height scale. Using AERMAP (Version 06341), terrain elevations will be determined using a method that interpolates the terrain elevation near each receptor.
Dispersion Coefficients:	A key feature of AERMOD's formulation is the use of directly observed variables of the boundary layer to parameterize dispersion; therefore, the choice of the use of the simple rural or urban dispersion coefficient is no longer available. The AERMOD model has the option of

assigning specific sources to have an urban effect, thus enabling AERMOD to employ enhanced turbulent dispersion associated with anthropogenic heat flux, parameterized by population size of the urban area. Since the proposed Project is not located in an urbanized area, urban boundary layer option will not be invoked.

Meteorological Data: Sequential hourly meteorological data will consist of Jacksonville surface and upper air data for the data period of 2001-2005. This data set is provided by and processed by Florida Department of Environmental Protection (FDEP) and is AERMOD ready.

Pollutants to be Modeled: The pollutants that are currently expected to be modeled are PM/PM_{10}, NO_x, SO_2, and CO.

Source Modeling Parameters: Representative combustion turbine performance and emissions data for the several operating configurations; including natural gas or ultra low sulfur fuel oil firing. The performance and emission data will be determined across 50, 75, and 100 percent load cases at ambient temperatures of 7, 59, 69, and 105 °F. Enveloping may be used to determine the worst-case hourly emission rates and operating parameters for each load case across ambient temperatures and operating scenarios that will be used for short-term modeling impacts. Emission rates and operating parameters for annual modeling impacts will be based on annual average ambient temperature data, at 100 percent load.

Significant Impact Area: It is anticipated that the maximum model predicted pollutant impacts will be less than their respective PSD SILs. However, if the predicted impact of one or more pollutants and applicable averaging periods are greater than the PSD SILs, then a significant impact area (SIA) will be determined and interactive cumulative source modeling will be performed for those pollutants to determine compliance with PSD increment limits. In this event, the proposed project will develop a methodology for compiling a cumulative source inventory and submit to the agency that methodology for approval.

Preconstruction Monitoring: It is anticipated that the maximum model predicted pollutant impacts will be less than the applicable PSD significant monitoring concentrations, as such, an exemption from pre-application monitoring requirements is requested. However, in the event the maximum model predicted impacts exceed the applicable PSD significant monitoring concentration for a given pollutant, then the existing ambient air quality monitoring network will be evaluated for representativeness of these data to the site location pursuant to requesting a waiver from the pre-application monitoring requirements for that pollutant.

It is anticipated that the NO_x emissions will be greater than 100 tpy; therefore, ozone will be subject to the PSD requirements. The existing ambient air quality monitoring network will be evaluated for representativeness of the ozone data to the site location pursuant to requesting a waiver from the pre-application monitoring requirements for ozone.

Additional Impacts: An analysis considering the impairment to soils and vegetation, as well as projected air quality impacts that may occur as the result of general commercial, residential, industrial, and other growth associated with the new major stationary source will be performed. The USEPA document *A Screening Procedure for the Impacts of Air Pollution Sources on Plant, Soils, and Animals* will serve as a basis for assessing the vegetation and soil impacts.

Toxics: No toxic modeling analysis is required.

Appendix F
Possible Future Combined Cycle - AAQIA Report

Combined Cycle Combustion Turbine – Ambient Air Quality Impact Analysis

The modeling analyses presented within this appendix are being provided as a supplement by JEA in order to demonstrate that this project both in its currently proposed SCCT state (presented in Sections 4 and 5 of the main application support document) and in its possible future planned conversion to CCCT mode of operation (presented here) will be protective of air quality in the area.

This CCCT AAQIA has been performed for those emitted criteria pollutants that are projected to be subject to PSD review (based on ultimate combined cycle operation) for which an AAQS exists (i.e., NO_x, PM_{10}, SO_2, and CO) and was conducted using the same modeling methodologies as the SCCT modeling presented in Sections 4 and 5 of the main application support document. Additionally, since the conversion has not yet gone through engineering design, the emissions contained within include only the major units (i.e., the two CCCTs with duct fired HRSGs) and are subject to change.

Following this introduction is a series of tables (similar to those in Sections 4 and 5 of the main application support document) that provide AERMOD model inputs and results for the Class II analyses and CALPUFF model inputs and results for the Class I analyses. As shown in the following tables, all model-predicted impacts are below the requisite thresholds indicating that the potential future conversion to CCCT operation will continue to be protective of air quality. It is important to note that the final AAQIA for the combined cycle conversion would be performed in detail (including any proposed ancillary emissions sources) in a PSD CCCT air permit application submittal to FDEP for review and approval at a later date.

Table F-1
Stack Parameters and Pollutant Emission Rates Used in the CCCT AERMOD Modeling Analysis

Period	Source[a]	Load	Stack Height (ft)	Stack Diameter (ft)	Exit Velocity (ft/s)	Exit Temp (°F)	Pollutant Emission Rate (lb/h)			
							NO_x	SO_2	PM/PM_{10}[d]	CO
Annual[b]	CCCT	100	160	18	62	184	17.36	8.81	24.89	N/A
Short-term[c]	**Gas – 24 hours per day**									
	CCCT	100	160	18	62	184	N/A	8.81	24.00	30.60
	Oil – 24 hours per day									
	CCCT	100	160	18	78	323	N/A	3.35	39.60	41.40

[a]Emissions for the CCCTs are per stack.
[b]For the annual modeling scenario, annualized emissions are the higher of 8,760 hours of operation on natural gas or 8,260 hours per year of operation on natural gas with an additional 500 hours per year of operation on ULSFO (each CCCT). When annual emissions are derived from a combination of operation on natural gas and ULSFO, the lowest exit temperature and exit velocity of the two fuels is conservatively assumed.
[c]For the short-term modeling scenario, emissions from operation on natural gas and operation on ULSFO were modeled separately since each fuel can be fired for 24-hours per day. CCCT emissions given by load are enveloped over several ambient temperatures and modes of operation to produce worst case operation by load.

Table F-2
AERMOD Model-Predicted Class II Impacts

Pollutant	Fuel	Averaging Period	Model-Predicted Impact[a] (μg/m³)	PSD Class II SIL[b] (μg/m³)	Exceed SILs?	De Minimis Monitoring Level[c] (μg/m³)	Pre-Construction Monitoring Required?
NO_x	NG/ULSFO[d]	Annual	0.20	1	NO	14	NO
SO_2	NG/ULSFO[d]	Annual	0.10	1	NO	--	N/A
	NG	24 Hour	1.17	5	NO	13	NO
	ULSFO	24 Hour	0.20	5	NO	13	NO
	NG	3 Hour	2.50	25	NO	--	N/A
	ULSFO	3 Hour	0.53	25	NO	--	N/A
PM/PM_{10}[e]	NG/ULSFO[d]	Annual	0.29	1	NO	--	N/A
	NG	24 Hour	3.19	5	NO	10	NO
	ULSFO	24 Hour	2.37	5	NO	10	NO
CO	NG	8 Hour	6.09	500	NO	575	NO
	ULSFO	8 Hour	5.13	500	NO	575	NO
	NG	1 Hour	10.81	2,000	NO	--	N/A
	ULSFO	1 Hour	8.89	2,000	NO	--	N/A

[a]Impacts represent the highest first high model-predicted concentration from all 5 years of meteorological data: 2001, 2002, 2003, 2004, and 2005 modeled and include operation of the two CCCTs with duct-fired HRSGs.
[b]Predicted impacts that are below the specified level indicate that the proposed project will not have predicted significant impacts for that pollutant and further modeling is not necessary for that pollutant.
[c]This criteria is used to determine if pre-construction ambient air monitoring is required to assess current and future compliance with Ambient Air Quality Standards.
[d]Impacts are from CCCT operation of 8,760 hours on natural gas (each) or 8,260 hours per year of operation on natural gas with an additional 500 hours per year of operation on ULSFO (each); whichever scenario produced the higher emissions profile.
[e] Note that the PM_{10} impacts are below the PM_{10} PSD Class II SILs and that the AAQS for $PM_{2.5}$ are significantly greater than the PM_{10} SILs. Therefore, if one were to conservatively assume that $PM_{2.5}$ impacts would be the same as the PM_{10} impacts (in accordance with the USEPA's guidance memorandum related to the interim implementation of NSR for PM 2.5), then the impacts would be significantly below the $PM_{2.5}$ AAQS.

Table F-3
Stack Parameters and Pollutant Emissions
Used in CALPUFF Modeling Analysis

Period	CCCT Load[(a)]	Stack Height (ft)	Stack Diameter (ft)	Exit Velocity (ft/s)	Exit Temp (°F)	Pollutant Emission Rate (lb/h)			
						NO_x	PM/PM_{10}[(b)]	SO_2	H_2SO_4[(c)]
Annual[(d)]	100	160	18	62	184	17.36	24.89	8.81	5.33
Short-term[(d)]	**Gas – 24 hours per day**								
	100	160	18	62	184	13.97	24.00	8.81	5.33
	Oil – 24 hours per day								
	100	160	18	78	323	73.40	39.60	3.35	1.73

[(a)]Emissions for the CCCTs are per stack. For the annual modeling scenario, annualized emissions are the higher of 8,760 hours of operation on natural gas or 8,260 hours per year of operation on natural gas with an additional 500 hours per year of operation on ULSFO (each). When annual emissions are derived from a combination of operation on natural gas and ULSFO, the lowest exit temperature and exit velocity of the two fuels is conservatively assumed. For the short-term modeling scenario, emissions from operation on natural gas and operation on ULSFO were modeled separately since each fuel can be fired for 24-hours per day. CCCT emissions at 100 percent load are enveloped over several ambient temperatures and modes of operation to produce worst case operation for this load.
[(b)]PM/PM_{10} emission rates represent both front and back half emissions.
[(c)]Assumes a percentage conversion of SO_2 to SO_3; then 100 percent of SO_3 conversion to H_2SO_4.
[(d)]Annual emissions are used for comparison of impacts to annual Class I SILs and annual Deposition Analysis Thresholds. Short-term emissions are used for comparison of impacts to short-term Class I SILs and Regional Haze.

Table F-4 Particle Speciation and Size Distribution for Natural Gas Operation				
			Emission Rate (lb/hr)	
Species Name	Geometric Mean Diameter (mm)	Size Distribution (%)	Filterable EC Emissions[a]	Non-$(NH_4)_2SO_4$ Condensable OC Emissions[b]
PM0P05	0.05	15	1.725	1.875
PM0P10	0.10	25	2.875	3.125
PM0P15	0.15	23	2.645	2.875
PM0P20	0.20	15	1.725	1.875
PM0P25	0.25	11	1.265	1.375
PM1P00	1.00	11	1.265	1.375
Subtotals			11.50	12.50
Total			24.00	

[a]Elemental Carbon (EC) includes all filterable emissions.
[b]Organic Carbon (OC) includes all condensable emissions.

Table F-5 Particle Speciation and Size Distribution for ULSFO Operation					
			Emission Rate (lb/hr)		
Species Name	Geometric Mean Diameter (mm)	Size Distribution (%)	Filterable EC Emissions[a]	Soils[b]	Non-$(NH_4)_2SO_4$ Condensable OC Emissions[c]
PM0P05	0.05	15	1.451	1.451	3.038
PM0P10	0.10	25	2.419	2.419	5.063
PM0P15	0.15	23	2.225	2.225	4.658
PM0P20	0.20	15	1.451	1.451	3.038
PM0P25	0.25	11	1.064	1.064	2.228
PM1P00	1.00	11	1.064	1.064	2.228
Subtotals			9.68	9.68	20.25
Total			39.60		

[a]Elemental Carbon (EC) includes half of filterable emissions.
[b]Soils includes half of filterable emissions.
[c]Organic Carbon (OC) includes all condensable emissions.

Table F-6
Regional Haze Results

Class I Area	Change in Extinction[a] (%)			Recommended Threshold (%)	Exceed?
	2001	2002	2003		
Gas – 24 hours per day					
Chassahowitzka	1.22	1.12	1.21	5	NO
Okefenokee	3.98	3.15	3.97	5	NO
St. Marks	0.82	1.00	1.09	5	NO
Wolf Island	1.74	1.64	1.39	5	NO
Oil – 24 hours per day					
Chassahowitzka	1.84	0.94	1.14	5	NO
Okefenokee	4.38	2.73	3.88	5	NO
St. Marks	0.63	1.18	1.13	5	NO
Wolf Island	1.44	1.83	1.46	5	NO

[a]Change in extinction was compared against the natural conditions presented in the FLAG 2000 document using Method 6 in CALPOST.

Table F-7
Deposition Results

Class I Area	Total Nitrogen Deposition[a] (kg/ha/yr)			Total Sulfur Deposition[b] (kg/ha/yr)			Deposition Analysis Threshold[c]
	2001	2002	2003	2001	2002	2003	
Chassahowitzka	1.33 E-04	1.75 E-04	1.05 E-04	2.31 E-04	2.82 E-04	2.17 E-04	1.0 E-02
Okefenokee	6.88 E-04	9.23 E-04	1.28 E-03	7.85 E-04	1.20 E-03	1.79 E-03	1.0 E-02
St. Marks	1.64 E-04	2.32 E-04	3.35 E-04	2.48 E-04	3.49 E-04	4.42 E-04	1.0 E-02
Wolf Island	3.81 E-04	5.78 E-04	7.26 E-04	6.04 E-04	9.37 E-04	1.04 E-03	1.0 E-02
Bradwell Bay	1.12 E-04	1.85 E-04	1.60 E-04	1.59 E-04	2.48 E-04	2.19 E-04	1.0 E-02

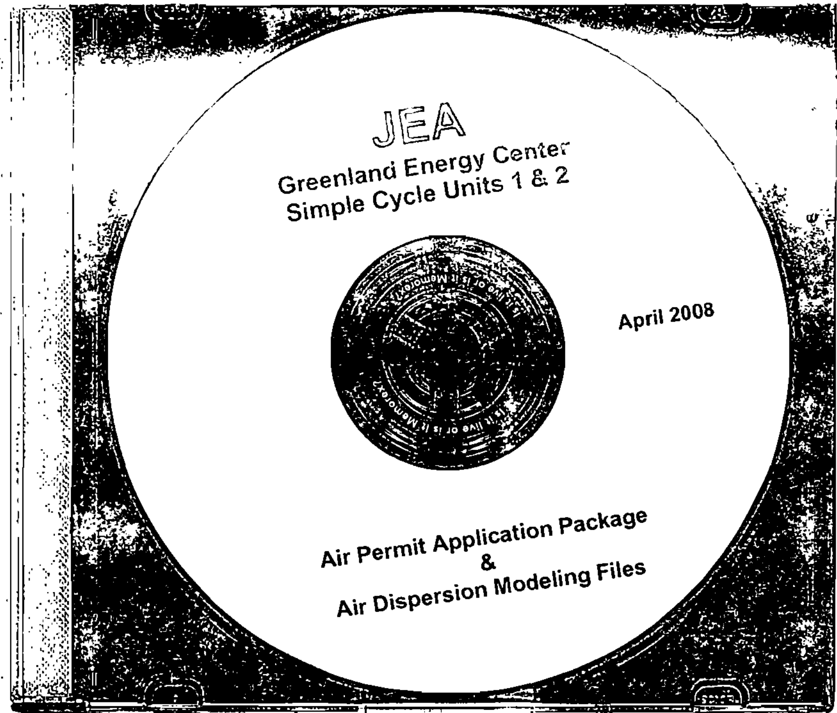
[a]Includes both wet and dry deposition with SO_4, NO_x, HNO_3, and NO_3 contributing to the nitrogen mass.
[b]Includes both wet and dry deposition with SO_2 and SO_4 contributing sulfur mass.
[c]For all areas east of the Mississippi River.

Table F-8
Class I Significant Impact Levels Modeling Results

Pollutant	Fuel	Averaging Period	Model-Predicted Impact[a] ($\mu g/m^3$) CW	OW	SMW	WIW	BBW	PSD Class I SIL[b] ($\mu g/m^3$)	Exceed SILs?
NO_x	NG/ULSFO[c]	Annual	0.0003	0.0018	0.0002	0.0008	0.0001	0.10	NO
SO_2	NG/ULSFO[c]	Annual	0.0002	0.0013	0.0002	0.0006	0.0001	0.08	NO
	NG	24 Hour	0.0067	0.0262	0.0054	0.0101	0.0034	0.20	NO
	ULSFO	24 Hour	0.0028	0.0093	0.0018	0.0035	0.0014	0.20	NO
	NG	3 Hour	0.0221	0.0589	0.0160	0.0399	0.0113	1.00	NO
	ULSFO	3 Hour	0.0085	0.0207	0.0067	0.0147	0.0049	1.00	NO
PM/PM_{10}	NG/ULSFO[c]	Annual	0.0009	0.0044	0.0009	0.0006	0.0006	0.16	NO
	NG	24 Hour	0.0235	0.834	0.0218	0.0349	0.0169	0.32	NO
	ULSFO	24 Hour	0.0469	0.1345	0.0300	0.0505	0.0273	0.32	NO

[a]Impacts represent the highest first high model-predicted concentration from all 3 years of meteorological data: 2001, 2002, and 2003 modeled at 100 percent load and include operation of the two CTGs with duct-fired HRSGs.
[b] Class I SILs are calculated as 4 percent of the PSD Class I Increment values. Predicted impacts that are below the specified levels indicate that the proposed project will not have predicted significant impacts for that pollutant and further modeling is not necessary for that pollutant.
[c]Impacts are from CCCT operation of 8,760 hours on natural gas (each) or 8,260 hours per year of operation on natural gas with an additional 500 hours per year of operation on ULSFO (each); whichever scenario produced the higher emissions profile.

Appendix G
Electronic Modeling Files


JEA
Greenland Energy Center
Simple Cycle Units 1 & 2
April 2008
Air Permit Application Package
&
Air Dispersion Modeling Files