

Florida Electrical Power Plant Siting Act Site Certification Application

Volume 3 of 3

Cane Island Power Park – Unit 4



Submitted by:
**Florida Municipal Power Agency
Kissimmee Utility Authority**

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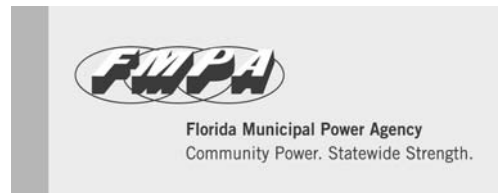


**FMPA – Cane Island Power Park
Unit 4
Combined Cycle Combustion Turbine**

**Prevention of Significant Deterioration
Air Permit Application**

April 2008

**Prepared for:
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Acronym List

AAQIA	Ambient Air Quality Impact Analysis
AAQS	Ambient Air Quality Standards
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
CAMR	Clean Air Mercury Rule
CALPUFF	California Puff
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
dv	Deciview
EC	Elemental Carbon
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
F.A.C.	Florida Administrative Code
FDEP	Florida Department of Environmental Protection
FGT	Florida Gas Transmission Company
FMPA	Florida Municipal Power Agency
FWS	Fish and Wildlife Service
GE	General Electric
GEP	Good Engineering Practice
Gulfstream	Gulfstream Natural Gas System L.L.C.

H ₂ S	Hydrogen Sulfide
H ₂ SO ₄	Sulfuric Acid Mist
ha	Hectares
HAP	Hazardous Air Pollutant
Hg	Mercury
HRSG	Heat Recovery Steam Generator
ISC	Industrial Source Complex
ISO	International Organization for Standardization
IWAQM	Interagency Workgroup on Air Quality Modeling
kW	Kilowatt
lb/h	Pound per Hour
LCC	Lambert Conformal Conic
LMDCT	Linear Mechanical Draft Cooling Tower
LNG	Liquefied Natural Gas
MBtu	Million British Thermal Unit
MM5	Mesoscale Meteorological Data - Generation 5
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
NPS	National Parks Service
NSPS	New Source Performance Standard
NSR	New Source Review
NWS	National Weather Service
O ₃	Ozone
OC	Organic Carbon
Pb	Lead
PG/MP	Pasquill Gifford/McElroy Pooler
PM/PM ₁₀	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 Engine
RH	Relative Humidity
rpm	Revolutions Per Minute
scf	Standard Cubic Feet
SCCT	Simple Cycle Combustion Turbine
SCR	Selective Catalytic Reduction
SER	Significant Emission Rate
SIL	Significant Impact Level
SO ₂	Sulfur Dioxide
SOA	Secondary Organic Aerosols
STG	Steam Turbine Generator
TCEC	Treasure Coast Energy Center
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

1.0 Introduction

Florida Municipal Power Agency (FMPA) is proposing to construct and operate a new natural gas fired combined cycle combustion turbine (CCCT) (Unit 4) at its existing Cane Island Power Park (CIPP) located near Kissimmee, Florida. The natural gas pipelines may also include vaporized liquefied natural gas (LNG), which is essentially no different from natural gas. The proposed CIPP Unit 4 and supporting ancillary equipment will join the existing units (Units 1, 2, and 3) at the CIPP. Pursuant to the requirements of Florida Rule 62-212.400, Florida Administrative Code (F.A.C.), FMPA is hereby submitting this Prevention of Significant Deterioration (PSD) Air Permit Application for the construction and initial operation of CIPP Unit 4 and associated equipment. The applicable air permit application forms are included in Appendix A of this volume.

The proposed Unit 4 will be a CCCT unit rated at approximately 300 megawatts (MW), firing natural gas as the fuel. Unit 4 will occupy approximately 9 acres adjacent to and north of Unit 3. New major support facilities for Unit 4 will include a diesel engine driven fire pump, a safe shutdown generator, and an eight-cell linear mechanical draft cooling tower (LMDCT).

This report is a technical support document for the PSD Air Permit Application. The following sections contain a project characterization, best available control technology (BACT) determination, air quality impact analysis (AQIA), and additional impact analyses designed to provide a basis for the Florida Department of Environmental Protection's (FDEP) preparation of an air construction permit for the Project.

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 CIPP is located in rural northwest Osceola County, Florida. Figure 2-1 shows the specific location of the Project, which is approximately 20 miles southwest of Orlando, 5 miles west of Kissimmee, and 1 mile northwest of Intercession City. The CIPP is situated on a slightly elevated ridge of dry sand surrounded by the wetlands of the Reedy Creek Swamp. The topography of the area is unpronounced and considered relatively flat.

2.2 Project Description

2.2.1 Existing Cane Island Power Park

The CIPP currently includes a nominal 40 MW simple cycle combustion turbine (SCCT) unit (Unit 1), a nominal 120 MW CCCT with a heat recovery steam generator (HRSG) and steam turbine (Unit 2), and a nominal 250 MW CCCT with an HRSG and steam turbine (Unit 3).

No modifications to CIPP's existing emission sources are proposed as part of this Project.

2.2.2 Proposed CIPP Unit 4

The Project installation will be a 1x1 combined cycle unit (Unit 4), which will include a General Electric (GE) 7FA combustion turbine generator (CTG), a duct fired HRSG, and a steam turbine generator (STG), and will be equipped with an evaporative cooler. Unit 4 will have a nominal rating of approximately 300 MW and will fire pipeline grade natural gas, exclusively. New major support facilities include a diesel engine driven fire pump, a safe shutdown generator, and an eight-cell LMDCT.

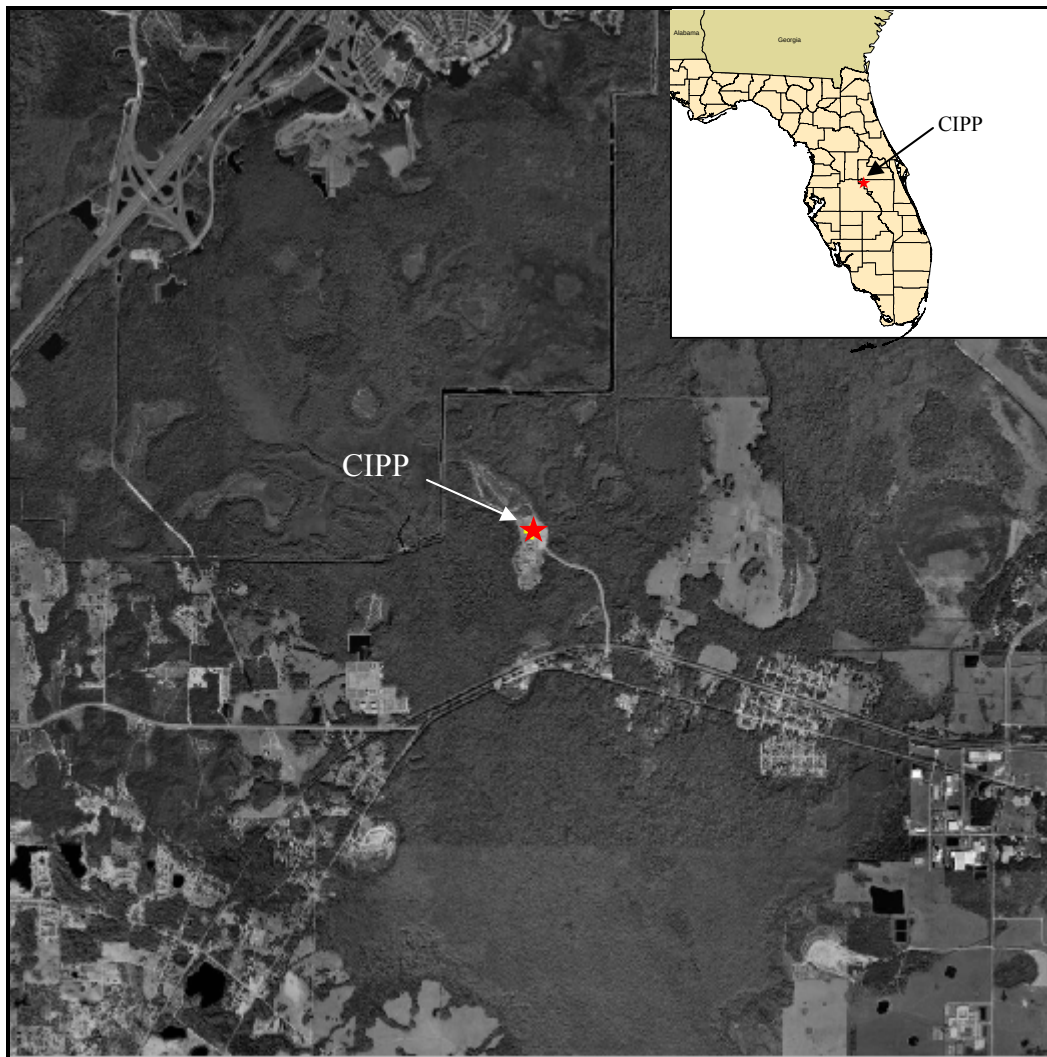


Figure 2-1
Proposed Project Location

Combustion Turbine Generator

The PSD application is based on a GE PG7241 FA enhanced CTG with modulating inlet guide vanes installed outdoors. The CTG unit will include the following major features:

- Single fuel firing system using pipeline-grade natural gas.
- Dry low NO_x (nitrogen oxides) combustion system.
- Direct connected generator with static excitation.
- Acoustic enclosure for turbine.
- Inlet air filter system with silencers and evaporative coolers.
- Lube oil systems.
- Static starting system.
- Fire detection/carbon dioxide fire protection systems.
- Mark VIe control system.
- Off-line/on-line water wash system.
- Package electrical and electronics control compartment.

Heat Recovery Steam Generator

The HRSG will convert waste heat from the CTG exhaust to steam for use in driving the STG. The HRSG is expected to be a natural circulation, three pressure, reheat unit with supplemental duct firing (593 MBtu/h) by natural gas only to maximize unit output. Selective catalytic reduction (SCR) for NO_x control is included (refer to Section 3.0 for further details). The HRSG will discharge to a metal exhaust stack approximately 160 feet tall. A stack damper will be included to minimize heat loss during unit shutdowns.

Steam Turbine Generator

The STG is expected to be a tandem-compound single reheat condensing turbine operating at 3,600 revolutions per minute (rpm). The steam turbine will have one high-pressure section with a nominal 2,100 pounds per square inch gauge (psig) throttle pressure, one intermediate-pressure section, and one low-pressure section. Turbine suppliers' standard auxiliary equipment; lubricating oil system; hydraulic oil system; and supervisory, monitoring, and control systems are included. A surface condenser is included for condensing steam from the turbine exhaust and will utilize a recirculating cooling tower system for cooling. A single synchronous generator is included that will be direct coupled to the steam turbine. Generator suppliers' standard auxiliary equipment; supervisory, monitoring, and control systems; and static excitation system are included.

2.2.3 Mode of Operation

The Unit 4 CCCT is designed for unlimited operation on natural gas, including an unlimited number of starts annually. However, approximately 300 starts are expected annually, with an expected breakdown of 50 cold starts, 200 warm starts, and 50 hot starts. The gas turbine/HRSG system may also operate in a pseudo simple cycle mode where steam from the HRSG bypasses the steam turbine electrical generator and is dumped directly to the condenser.

2.2.4 Fuel

The primary fuel for Unit 4 will be natural gas from existing Florida Gas Transmission Company (FGT) and Gulfstream Natural Gas System L.L.C. (Gulfstream) pipelines.

2.2.5 Air Quality Control

Based on the BACT analysis, emission control for NO_x will be by the use of combustion turbine dry low NO_x (DLN) burners and SCR. Control of other pollutants will be by good combustion control and use of natural gas. Please refer to Section 3.0 for further details.

2.3 Project Emissions

This section discusses the potential to emit (PTE) of all regulated PSD air pollutants resulting from the Project. Emissions from the Project will be generated from the following emissions units:

- One GE CCCT/HRSG with supplemental duct firing (Unit 4).
- One diesel engine driven fire pump with associated 500 gallon ultra-low sulfur fuel oil (ULSFO) day storage tank.
- One safe shutdown generator with associated 1,000 gallon ULSFO day storage tank.
- One eight-cell LMDCT.

The emissions for each of these emission sources are presented in Table 2-1. Emissions from the ULSFO day tanks are insignificant. Detailed spreadsheets used to estimate these emissions are presented in Appendix C. In Table 2-2, the Project's aggregate annual PTE is presented and compared to the applicable PSD significant emission rates (SERs) to determine which of the Project's criteria pollutants are subject to PSD review, as further discussed in Subsection 2.4.1.2. The following sections briefly describe the basis for the emission calculations.

**Table 2-1
Project Potential to Emit**

Pollutant	Unit 4 (lb/h)^(a)	Diesel Engine Fire Pump (lb/h)	Safe Shutdown Generator (lb/h)	Project PTE^(b) (tons/yr)
CO	40.80	0.33	1.12	178.82
NO _x	17.60	3.47	9.65	78.10
PM/PM ₁₀ ^(c)	39.70	0.08	0.29	176.82
SO ₂ ^(d)	10.34	0.00	0.01	45.29
VOC	5.30	0.66	0.66	23.30
H ₂ SO ₄ ^(e)	5.54	0.00	0.02	24.27
Lead ^(f)	0.00	0.00	0.00	0.00
Mercury ^(f)	0.00	0.00	0.00	0.00
Fluorides	0.00	0.00	0.00	0.00
H ₂ S	0.00	0.00	0.00	0.00
Total Reduced Sulfur	0.00	0.00	0.00	0.00

^(a)Regardless of operating mode, emissions are based on operation of the combustion turbine at 100 percent load, 8,760 hours per year, and at an ambient temperature at ISO conditions and includes emissions from the duct burner.

^(b)Includes emissions from the diesel engine fire pump, safe shutdown generator, and the cooling tower (PM/PM₁₀ [particulate matter/particulate matter less than 10 microns] emissions).

^(c)Includes front and back half emissions from the CTG.

^(d)Based on a natural gas sulfur content of 2 grains/100 scf. Emissions from the diesel engine fire pump and safe shutdown generator are based on firing ULSFO.

^(e)Includes the effects of SO₂ oxidation and assumes 100 percent conversion of SO₃ to H₂SO₄.

^(f)Based on AP-42 emission factors.

Note: Detailed calculations are contained in Appendix C.

Table 2-2 Comparison of Potential Annual Emissions from the Project to PSD SERs			
Pollutant	Total Project Potential Annual Emissions^(a) (ton/yr)	PSD SERs (tons/h)	PSD Review Required? (Yes/No)
CO	178.82	100	Yes
NO _x	78.10	40	Yes
PM/PM ₁₀ ^(b)	176.82	25/15	Yes
SO ₂ ^(c)	45.29	40	Yes
VOC	23.30	40	No
H ₂ SO ₄ ^(d)	24.27	7	Yes
Lead ^(e)	0.00	0.6	No
Mercury ^(e)	0.00	0.1	No
Fluorides	0.00	3	No
H ₂ S	0.00	10	No
Total Reduced Sulfur	0.00	10	No
^(a)Total project potential annual emissions are from Table 2-1. ^(b)Includes front and back half emissions from the CTG. ^(c)Based on a natural gas sulfur content of 2 grains/100 scf. Emissions from the diesel engine fire pump and safe shutdown generator are based on firing ULSFO. ^(d)Includes the effects of SO₂ oxidation and assumes 100 percent conversion of SO₃ to H₂SO₄. ^(e)Based on AP-42 emission factors. Note: Detailed calculations are contained in Appendix C.			

2.3.1 Unit 4 Emissions

Performance data for Unit 4 at loads of 40, 50, 75, and 100 percent, and ambient air temperatures of 19° F, 59° F, 73° F, and 102° F are provided in Appendix D of this volume.

Ambient temperature data were selected based on meteorological data from Orlando, Florida. An ambient temperature of 19° F represents the extreme site minimum temperature and corresponds to maximum heat input and power generation. An ambient temperature of 73° F represents the average annual site temperature, which is representative of the average heat input rate. An ambient temperature of 102° F represents the maximum site temperature and corresponds to the lowest heat input rate for the combustion turbine. An ambient temperature of 59° F and a relative humidity of 60 percent were also selected because they represent ISO (International Organization for Standardization) conditions.

PTE for Unit 4, which is presented in Table 2-1, was estimated based on the hourly emission rate for each pollutant at ISO conditions and 100 percent load, natural gas firing in the CTG and the duct burner, and evaporative cooling. The PTE for Unit 4 includes the use of BACT, which is discussed in Section 3.0.

2.3.2 Diesel Engine Fire Pump

A 290 brake horsepower (bhp) diesel engine fire pump is proposed to be installed. The manufacturer specification sheet for the diesel engine fire pump is provided in Appendix B. The emissions calculations for the diesel engine 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 diesel engine fire pump were based on 52 hours per year of operation for testing purposes.

2.3.3 Safe Shutdown Generator

The 750 kilowatt (kW) safe shutdown generator will fire only ULSFO. The generator will be subject to occasional testing to ensure operability and will be used for service only when the transmission connection is lost and the plant shuts down. When the transmission lines are lost (plant goes black), the generator would start to provide power to maintain the plant in a safe shutdown condition. It will only be run for short test periods when the plant is running, and will otherwise operate only when Unit 4 is down and auxiliary power is lost. It is estimated that the safe shutdown generator will operate approximately 200 hours per year. Potential emissions are based on vendor data and are presented in Appendix B of this volume. Detailed emissions calculations are presented in Appendix C.

2.3.4 Linear Mechanical Draft Cooling Tower

The Project will utilize a multiple cell, mechanical draft, counterflow cooling tower for plant cooling. The cooling tower will be of fiberglass construction and installed on a reinforced concrete basin, which will include a pump intake structure housing the two 50 percent capacity circulating water pumps and one 100 percent capacity auxiliary cooling water pump. A circulating water chemical feed system will be included. Makeup water to the cooling tower is expected to be from treated sewage plant effluent (reclaimed water). Provisions will be included to utilize municipal water and ground water as emergency sources of cooling tower makeup. The cooling tower will be equipped with drift eliminators with a design drift rate of 0.0005 percent of the circulating water flow rate.

The basic principle behind all cooling towers is to cool water using ambient air. Circulating cooling water will remove heat from the steam, causing it to condense. The heated circulating cooling water is transported to the cooling tower to dissipate the heat into the atmosphere. The circulating water is sprayed into the cooling tower as a coarse mist that cascades down a fill material. As the circulating water falls, air contacts the water, allowing a transfer of heat from the water to the cooler atmospheric air. The draft, which causes the atmospheric air to pass through the cascading water, is created mechanically with fans. The cooled circulating water is then collected in the cooling tower basin, where it is pumped from the cooling tower back to the condenser water boxes, repeating the process.

During the cooling process, small water droplets, known as cooling tower drift, escape to the atmosphere through the cooling tower exhaust. To minimize this effect, the tower will be equipped with drift eliminators to provide multiple directional changes of airflow while preventing the escape of water droplets.

Dissolved solids found in cooling tower drift typically consist of naturally occurring mineral matter, chemicals for corrosion inhibition, etc. Particulate matter is emitted when the drift droplets dispersed in the atmosphere evaporate and leave airborne fine particulate matter formed by crystallizations of dissolved solids.

Based on the type and efficiency of drift eliminators, drift droplets of varying sizes containing dissolved solids can be generated. For the purpose of this project, it is assumed that 100 percent of the drift droplets are small enough so that all the drift generated will be dispersed and lose water due to evaporation, resulting in emissions of particulate matter. PM/PM₁₀ emissions calculations for the LMDCT are presented in Appendix C.

2.4 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.

2.4.1 Rule Applicability to the Facility

This section provides a review of the rule applicability for the facility.

2.4.1.1 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 Code of Federal Regulations (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 Environmental Protection Agency (EPA) has approved Florida's NSR Program. Accordingly, Florida's regulations at Chapter 62-212, F.A.C., apply in Florida.

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 National Ambient Air Quality Standards (NAAQS). 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 NAAQS. A review of the air quality attainment status of Osceola County reveals that CIPP, and thus 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*.

2.4.1.2 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 NAAQS 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 carefully reviewed prior to construction to ensure compliance with the NAAQS, the applicable PSD air quality increments, and the requirements to apply BACT to minimize the emissions of air pollutants.

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. The CIPP is one of the 28 major source categories (i.e., fossil fuel fired steam electric plant) and has a PTE greater than 100 tpy for at least one regulated pollutant; therefore, it is considered an existing major PSD source.

Because the proposed Project is locating at an existing major stationary source, PSD applicability is determined on a pollutant-by-pollutant basis by comparing the emissions increase of each pollutant against the following PSD SERs:

- Nitrogen oxides (NO_x)--40 tpy.
- Sulfur dioxide (SO₂)--40 tpy.
- Particulate matter (PM)--25 tpy.
- Particulate matter less than 10 microns (PM₁₀)--15 tpy.
- Carbon monoxide (CO)--100 tpy.
- Ozone (O₃)--NO_x or volatile organic compounds (VOCs)--40 tpy.
- Lead (Pb)--0.6 tpy.
- Mercury (Hg)--0.1 tpy.
- Fluorides--3 tpy.
- Sulfuric acid mist (H₂SO₄)--7 tpy.
- Hydrogen sulfide (H₂S)--10 tpy.
- Total reduced sulfur compounds--10 tpy.

As presented in Table 2-2, the estimated potential emissions of NO_x, SO₂, CO, PM/PM₁₀, and H₂SO₄ resulting from the proposed Project exceed the PSD SERs of 40, 40, 100, 25/15, and 7 tpy, respectively. Therefore, the Project's emissions of NO_x, SO₂, CO, PM/PM₁₀, and H₂SO₄ are subject to PSD review. Because emissions of VOCs are below the PSD SERs of 40 tpy, the Project is not subject to PSD review for VOCs. The PSD review includes a BACT analysis, an AQIA, and an assessment of the Project'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 are included in Sections 3.0, 4.0, and 5.0, respectively.

2.4.2 Rule Applicability to Unit 4

The following sections include a discussion of the applicability of regulations to the Unit 4 combustion turbine and the duct burner.

2.4.2.1 New Source Performance Standards. The New Source Performance Standards (NSPSs) 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.

The combustion turbine and duct burner are both 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 SO₂ as follows:

- NO_x--15 ppm (parts per million) at 15 percent O₂ 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--96 ppm at 15 percent O₂ 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.
- SO₂--The rule includes a fuel emission standard or a fuel sulfur standard equivalent to potential SO₂ emissions of 0.060 lb SO₂/MBtu.

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

2.4.2.2 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 HAPs at a rate of 25 tons or more per year. The CIPP is an existing major source of HAP emissions. The proposed project will, therefore, be subject to the CT MACT. However, the proposed combustion turbine will fire only natural gas and meets the definition of a lean pre-mix natural gas fired turbine and, thus, is exempt from meeting the emission requirements of this rule. Only initial notification requirements will be applicable. It should be noted that the CT MACT considers duct burners and waste heat recovery units as steam generating units and, thus, are not considered as affected units under the CT MACT. However, the CT MACT recognizes that it is usually difficult to separately monitor emissions from the turbine and duct burner, so affected sources are allowed by the CT MACT to meet the required emission limitations for the combustion turbines with their duct burners in operation. Since there is no emission limitation that is applicable, it is assumed that the combined cycle system is in compliance with the MACT requirements.

2.4.3 Rule Applicability to the Diesel Engine Fire Pump and the Safe Shutdown Generator

Reciprocating internal combustion engines (RICEs) rated greater than 500 bhp and located at major HAP sources are regulated by the RICE MACT (40 CFR Part 63, Subpart ZZZZ). The diesel engine fire pump is rated at 290 bhp and is exempt from the requirements of RICE MACT. The safe shutdown generator is rated greater than the 500 bhp applicability threshold and, thus, is an affected unit under the RICE MACT. However, a new emergency stationary RICE located at a major source of HAPs is subject only to the initial notification requirements of 40 CFR 63.6645(d). Since the purpose of the safe shutdown generator will be for emergency situations when the normal source of power is not available to the facility, it will be considered as emergency stationary RICE and, therefore, subject only to the initial notification requirements of the RICE MACT.

The diesel engine fire pump and safe shutdown 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 safe shutdown generator will be dependent on the engine model year. Therefore, the exact emission standards applicable to the safe shutdown generator cannot be identified until the engine is purchased. The fire pump engines will need to meet the emission requirements listed in Table 4 of the 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 because 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. FMPA will purchase certified engines that will meet the appropriate emission limits.

2.4.4 Rule Applicability to the LMDCT

There are no MACT standards or NSPS that apply to the cooling tower. Additionally, none of the standards included in 62-296, F.A.C. apply to the cooling tower. The Cooling Tower MACT standard (40 CFR Part 63, Subpart Q), adopted by reference in Rule 62-204.800(11)(b)10, F.A.C., prohibits the use of chromium-based water treatment chemicals in industrial process cooling towers. FMPA does not and will not use such chemicals in the cooling tower.

2.4.5 Excess Emissions

As with other CCCTs of this size and type, excess emissions during startup, shutdown, and malfunction are likely to exceed the duration of excess emissions allowed in accordance with Rule 62-210.700(1), F.A.C. In accordance with Rule 62-210.700(5), F.A.C., FMPA is requesting that the air permit for the Project allow for excess emissions from startups and shutdowns greater than 2 hours per 24 hour period. Because Unit 4 is almost identical to the Treasure Coast Energy Center (TCEC) Unit 1, FMPA requests that a condition similar to Condition 18 of the Applicable Standards and Regulations Section of the TCEC Unit 1 permit issued by FDEP on May 17, 2006, be included in the Project permit. In general, it is requested that, in a 24 hour period, this condition allow for 6 hours of excess emissions during a cold start of the steam turbine/HRSG system, 4 hours of excess emissions during a warm start of the steam turbine/HRSG, and 3 hours of excess emissions for the shutdown of the combined cycle operation. It is also requested that, in the event there is a trip during a startup or during a 24 hour period that contains a startup, the permit allow for additional excess emissions during a startup subsequent to a unit trip (i.e., the allowable excess emissions clock starts over after a unit trip that results in the need to restart the unit).

2.4.6 Dry Low NO_x Burner Tuning

As allowed in the TCEC permit issued by FDEP on May 17, 2006, FMPA is requesting that the permit for this Project allow for exclusion of Continuous Emissions Monitoring System (CEMS) data collected during initial or other major DLN burner tuning sessions from the CEMS compliance demonstration. FMPA is requesting that a condition similar to Condition 20 of the Applicable Standards and Regulations Section of that permit issued by FDEP be included in the proposed CIPP Unit 4 permit.

3.0 Best Available Control Technology

A detailed BACT analysis for the Project has been included as Appendix D. Emissions for the BACT analysis are based on unlimited natural gas firing for Unit 4 at ISO conditions. The following is a summary of the BACT determination for Unit 4:

- NO_x emissions--BACT was determined to be the use of low NO_x burners and an SCR to achieve 2 ppmvd (parts per million volumetric dry) at 15 percent O₂.
- CO emissions--BACT was determined to be the use of good combustion practices.
- PM/PM₁₀ emissions--BACT was determined to be the use of good combustion controls and the use of natural gas.
- VOC emissions--A BACT analysis was not required for this emission parameter since annual emissions will be below the PSD major modification thresholds.
- SO₂ emissions--BACT was determined to be the use of natural gas.
- H₂SO₄ emissions--BACT was determined to be the use of natural gas.

4.0 Class II Ambient Air Quality Analysis

The following sections discuss the air dispersion modeling methodology and the modeling results from the Ambient Air Quality Impact Analysis (AAQIA) for the proposed Project. This AAQIA has been performed for those emitted criteria pollutants subject to PSD review for which an AAQS exists (i.e., NO_x, PM₁₀, SO₂, and CO). The AAQIA was conducted in accordance with the USEPA's 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 FMPA on January 11, 2008. The FDEP provided verbal approval of the protocol with minor changes during the project kickoff meeting on January 15, 2008. A copy of the updated protocol (based on requested changes by FDEP), 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 the 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 combustion turbine operating at several different loads (40, 50, 75, and 100 percent with duct firing) over a range of ambient temperatures (19, 59, 73, and 100° 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 C. “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 diesel engine fire pump, safe shutdown generator, and the cooling tower were also included in the modeling. Emissions data for these emission units are included in Appendix C. Because the diesel engine fire pump is only operated in emergency situations and for occasional testing to ensure operability, emissions from the emergency fire pump in the modeling are based on operating 1 hour per day and 52 hours per year. The safe shutdown generator is assumed to operate 24 hours per day up to a maximum of 200 hours per year.

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 United States Geological Survey (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 will not be invoked.

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

CTG Load	Stack Height (ft)	Stack Diameter (ft)	Exit Velocity (ft/s)	Exit Temp (°F)	Pollutant Emission Rate (lb/h)			
					NO _x	CO	PM/PM ₁₀	SO ₂
100% with Duct Firing	160	18	57.63	165	18.50	42.80	40.10 ^(a)	10.81
75%	160	18	47.73	166	11.20	25.00	22.10 ^(a)	6.86
50%	160	18	40.08	157	8.90	20.40	21.30 ^(a)	5.48
40%	160	18	36.67	154	7.90	18.40	20.90 ^(a)	4.84
Fire Pump ^(b)	15.17	0.42	184.08	855	Ann - 2.06E-02	1 hr - 3.26E-01 8 hr - 4.08E-02	24 hr - 3.46E-03 Ann - 4.93E-04	3 hr - 9.51E-04 24 hr - 1.19E-04 Ann - 1.69E-05
Safe Shutdown Generator ^(c)	24	0.83	192.82	816	Ann - 2.20E-01	1 hr - 1.12E+00 8 hr - 1.12E+00	24 hr - 2.92E-01 Ann - 6.66E-03	3 hr - 1.11E-02 24 hr - 1.11E-02 Ann - 2.54E-04
Cooling Tower ^(d)	56	30	23.67	91.52	--	--	24 hr - 8.27E-02 Ann - 8.27E-02	--
^(a) PM/PM ₁₀ emission rates represent both front and back half emissions including the effects of SO ₂ oxidation. ^(b) Emissions from the fire pump are based on operation for testing purposes. As such, the emissions for the above averaging periods are based on a ratio of the averaging period of concern to 1 hour of operation per day and 52 hours of operation per year. ^(c) Emissions from the safe shutdown generator are based on 24 hours per day and 200 hours of operation per year. ^(d) Emissions given are per cooling tower cell.								

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 the following:

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

$$H_g = H + 1.5 L$$

where:

H_g = 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 CIPP facility and the new Unit 4 addition were analyzed to determine the potential to influence the plume dispersion from the combustion turbine 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 height for the combined cycle Unit 4 stack is 60.29 meters (197.80 ft). The proposed Project stack height is 48.77 meters (160 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 meter spacing; the second tier extends from 1 km to 2.5 km with 250 meter spacing; the third tier extends from 2.5 km to 5 km with 500 meter spacing; and the fourth tier extends from 5 km to 10 km with 1,000 meter spacing. Receptors were placed at 50 meter intervals along the property boundary (i.e., that area to which public access is physically restricted).

Terrain elevations at receptors were obtained from 7.5 minute 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 the 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 (1999 – 2003) of meteorological data from the Orlando International Airport (MCO) 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. MCO is certainly in close proximity to the facility being located only 16 miles northeast. Additionally, the elevation of MCO (106 ft) is similar to that of the facility (82 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.

MCO has numerous years of data available for use in air dispersion modeling. The simulations presented here use the 5-year data set from 1999 through 2003 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 MCO 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 MCO 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, MCO is one of the few major meteorological stations in Florida that is located inland, distanced from the immediate effects of the Gulf of Mexico or Atlantic Ocean.

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 October 2007) 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 concentration.

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 MCO. The results of the AERSURFACE simulation are given below.

Location	Albedo	Bowen Ratio	Surface Roughness
Facility	0.15	0.34	0.61
MCO	0.16	0.59	0.09
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 MCO 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 MCO 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 PTE exceeds the PSD significant emission thresholds for NO_x, SO₂, PM/PM₁₀, and CO. In accordance with the approved modeling protocol, AERMOD air dispersion modeling was performed (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 preconstruction 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 [AAQS] analyses) are required.

If any of the maximum impact source groups, from each pollutant and averaging period, occurred at the edge of or beyond the 100 meter fine grid, a 100 meter refined receptor grid would be placed around the impact to ensure that an absolute maximum concentration was obtained from the model. This procedure was not required for any pollutants, because all of the maximum impacts were within the 100 meter fine grid.

Table 4-2
AERMOD Model-Predicted Class II Impacts

Pollutant	Averaging Period	Model-Predicted Impact ^(a) (µg/m ³)				PSD Class II SIL ^(b) (µg/m ³)	Exceed SILs?	De Minimis Monitoring Level ^(c) (µg/m ³)	Preconstruction Monitoring Required?
		100%	75%	50%	40%				
NO _x	Annual	0.90	0.90	0.90	0.90	1	NO	14	No
SO ₂	Annual	0.08	0.06	0.06	0.05	1	NO	--	No
	24 Hour	0.95	0.71	0.67	0.63	5	NO	13	No
	3 Hour	2.10	1.58	1.50	1.42	25	NO	--	No
PM/PM ₁₀ ^(d)	Annual	0.31	0.21	0.25	0.27	1	NO	--	No
	24 Hour	4.92	4.92	4.92	4.92	5	NO	10	No
CO	8 Hour	33.78	33.78	33.78	33.78	500	NO	575	No
	1 Hour	103.38	103.38	103.38	103.38	2,000	NO	--	No

^(a)Impacts represent the highest first high model-predicted concentration from all 5 years of meteorological data: 1999, 2000, 2001, 2002, and 2003 modeled at each corresponding load.

^(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 preconstruction ambient air monitoring is required to assess current and future compliance with AAQS.

^(d)Note that the PM₁₀ impacts are below the PSD Class II SILs, and the AAQS for PM_{2.5} are significantly greater than the PM₁₀ SILs. Therefore, if one were to conservatively assume that PM_{2.5} impacts would be the same as the PM₁₀ 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.

Additionally, the maximum predicted concentrations are less than the preconstruction monitoring de minimis levels for each pollutant and applicable averaging period. As given in rule 62-212.400(3)(e)1.e, F.A.C., no de minimis air quality level is provided for ozone. However, as allowed by that rule, since the project's PTE of both NO_x and VOC are each below 100 tpy, the requirements for monitoring of ozone shall not apply. Therefore, by this application, the applicant requests an exemption from the PSD preconstruction monitoring requirements. Electronic copies of all Class II modeling input and output files are included in Attachment F.

5.0 Class I Ambient Air Quality Analysis

As part of the air impact evaluation for the addition to the CIPP site, analyses of the proposed Project's effect on all Class I areas within 200 km was performed. Specifically, the Chassahowitzka Wilderness Area (CWA) is the only Class I area of concern for this Project. The CWA is a PSD Class I area located in central Florida along the Gulf of Mexico coast, approximately 113 km northwest of the proposed project site. 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 January 11, 2008 (Appendix E). The following sections include discussions of the air modeling approach to assess impacts at CWA as well as the model-predicted impacts from the Project onto the CWA.

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 CWA. 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. 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.

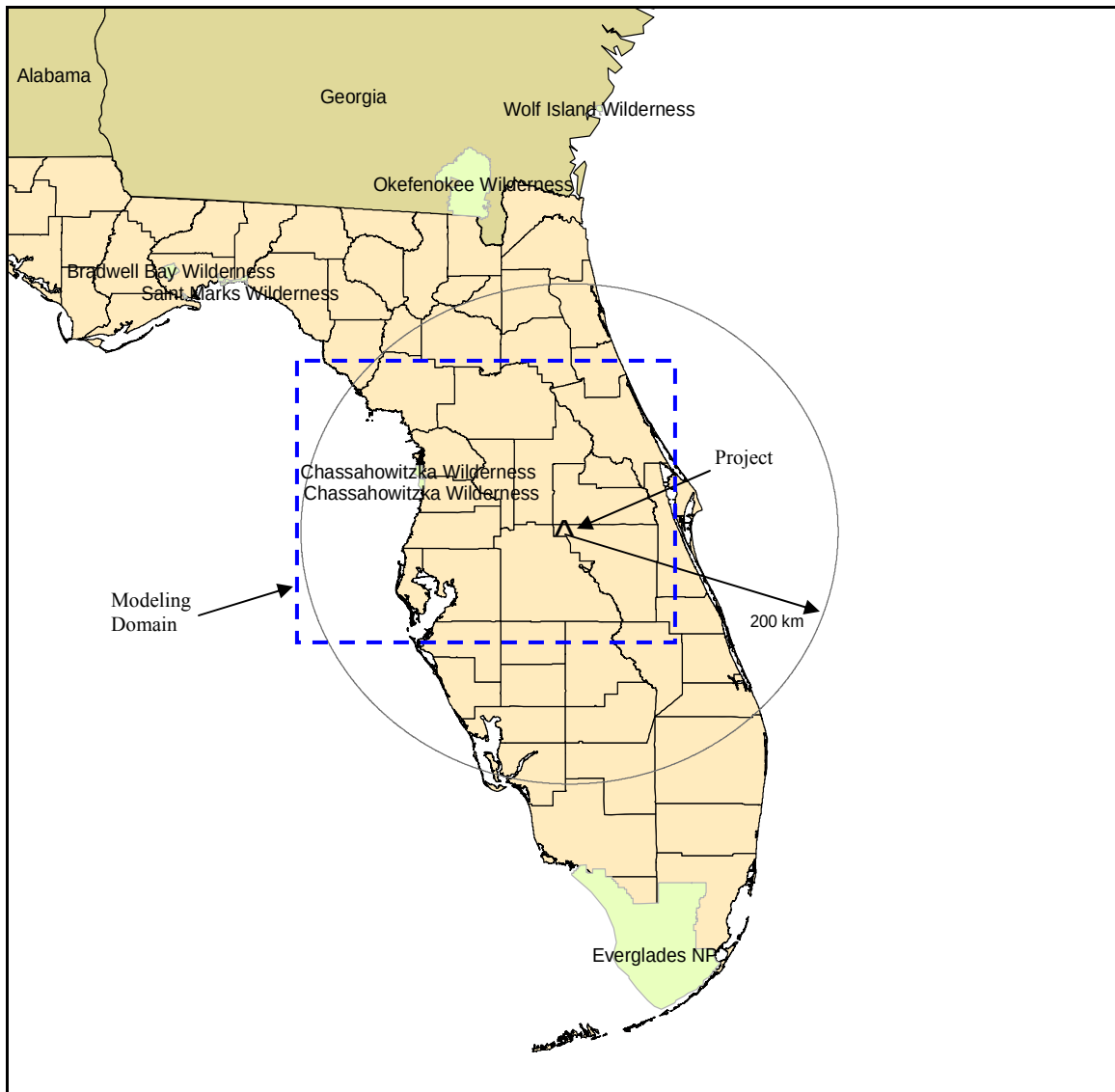


Figure 5-1
Proposed Project Location and Class I Areas

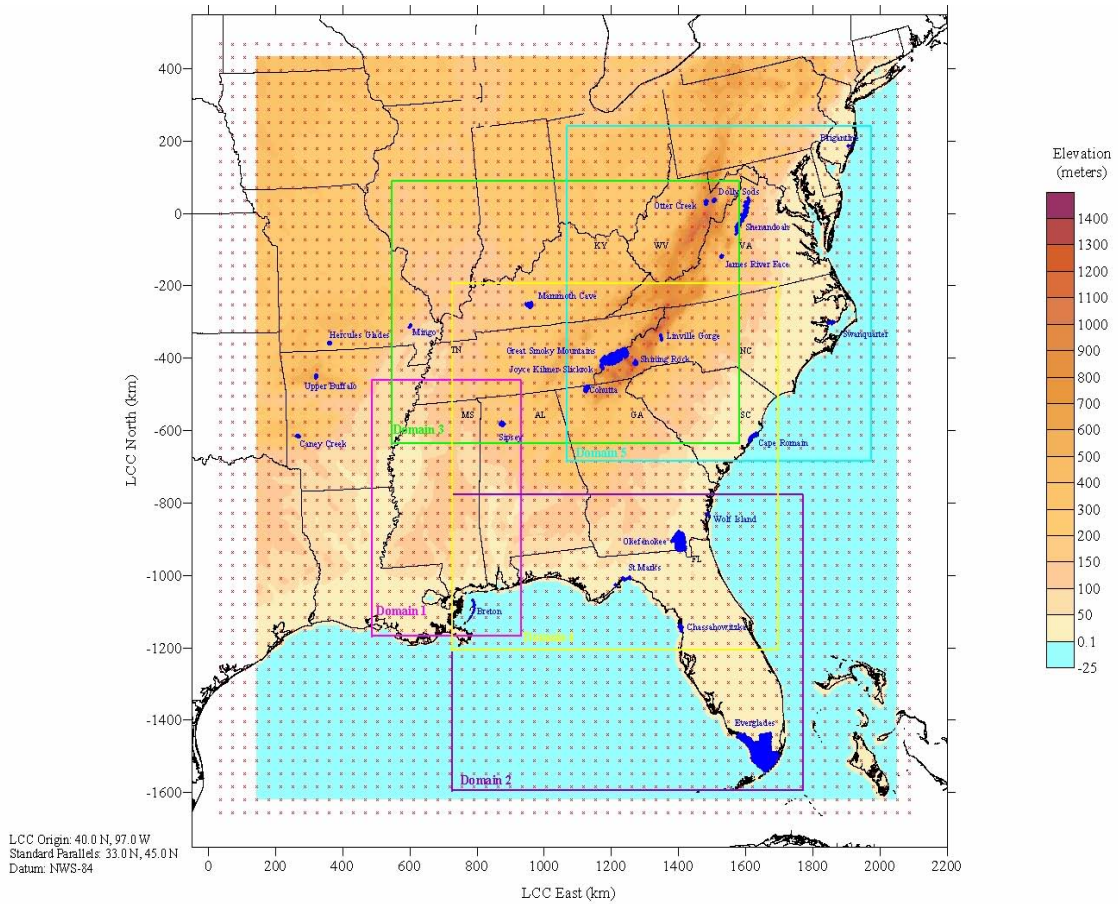


Figure 5-2
VISTAS 4 km CALMET Sub-Domains

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 area, which were created and distributed by the National Parks Service (NPS). Specifically, the array consists of receptors spaced to cover the extent of the 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 Mesoscale Meteorological Data - Generation 5 (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 data set for the entire VISTAS region from the North Carolina Department of Environment and Natural Resources.

**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	<u>Regional Haze:</u> Highest predicted 24 hour change as processed by CALPOST. <u>Class I SILs:</u> Highest predicted concentrations at the applicable averaging periods for those pollutants that exceed the respective PSD SERs. <u>Deposition:</u> 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 National Park, 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.
PG/MP = Pasquill Gifford/McElroy Pooler. ISC = Industrial Source Complex.	

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 air 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: Interagency Workgroup on Air Quality Modeling (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 were 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 meter land use data set.
- References for these and other CALMET data sets 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 the

Class I area 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 292 km in the east-west (x) direction and 204 km in the north-south (y) direction was used for the refined modeling analysis. The southwest corner of the domain is located at 1,317.995 km Easting and -1,254 km Northing (LCC, National Weather Service [NWS]-84, 6,370 km Radius Global Sphere). The grid resolution for the domain was 4 km. A grid spacing of 4 km yields 73 grid cells in the x-direction and 51 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., 19, 59, 73, and 102° 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/PM₁₀ (filterable and condensable), SO₂, and SO₄ (as H₂SO₄). Table 5-2 contains the stack parameters and emission rates modeled in CALPUFF. Furthermore, in accordance with guidance from the NPS, the PM/PM₁₀ emissions were speciated based on size and composition and, therefore, were broken into the following constituents: elemental carbon (EC) and organic carbon (OC) for the regional haze analysis. Specifically, guidance from the NPS on PM speciation was found in the Emissions & Control Technology area of their Web site. In accordance with the NPS, for natural gas fired combustion turbines, all the filterable portion of PM/PM₁₀ emissions are considered EC and all non-(NH₄)₂SO₄ condensables are considered to be OC.

The EC and OC emissions were further speciated based on size. In accordance with NPS guidance, all particles were assumed to be 1 micron or less for combustion turbines. Table 5-3 presents size distribution for EC and OC particulates as recommended by the 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

Cane Island Unit 4								
CTG Load	Stack Height (ft)	Stack Diameter (ft)	Exit Velocity (ft/s)	Exit Temp (°F)	Pollutant Emission Rate (lb/h)			
					NO _x	PM/PM ₁₀ ^(a)	SO ₂	H ₂ SO ₄ ^(b)
100% with Duct Firing	160	18	57.63	165	18.50	40.10	10.81	5.85

^(a)PM/PM₁₀ emission rates represent both front and back half emissions including the effects of SO₂ oxidation.
^(b)Assumes a percentage conversion of SO₂ to SO₃; then 100 percent of SO₃ conversion to H₂SO₄.

Table 5-3
Particle Size Distribution

Species Name	Geometric Mean Diameter (mm)	Size Distribution (%)	Emission Rate (lb/hr)	
			Filterable EC Emissions ^(a)	Non-(NH ₄) ₂ SO ₄ Condensable OC Emissions ^(b)
PM1P00	1.00	11	1.639	2.772
PM0P25	0.25	11	1.639	2.772
PM0P20	0.20	15	2.235	3.780
PM0P15	0.15	23	3.427	5.796
PM0P10	0.10	25	3.725	6.300
PM0P05	0.05	15	2.235	3.780
Subtotals			14.90	25.20

^(a)EC includes all filterable emissions.
^(b)OC includes all condensable emissions.

5.2 CALPUFF Analyses Performed

The preceding model inputs and settings for the CALPUFF modeling system were used to complete the Class I analyses on the CWA, 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 the CWA, for ammonium sulfates, ammonium nitrates, and PM, by appropriately characterizing model predicted outputs of SO₄, NO₃, and PM₁₀ concentrations. PM₁₀ emissions were speciated into filterable and condensable PM size categories using NPS speciation spreadsheets.

Visibility

Visibility is an AQRV for the CWA. 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 CWA 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:

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

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 the following:

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

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 dv that simply quantifies the percent change in visibility due to the operation of a source is calculated as follows:

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

Background Visual Ranges and Relative Humidity Factors

The background visual range is based on data representative of historical conditions at the CWA. The background visual range, or constituents thereof, for the CWA was obtained from the Phase I FLAG Report, December 2000. The average relative humidity (RH) factor for each day was computed by determining the RH factor for each hour's RH for the 24 hour period that the impact occurred. This factor, based on each hour's RH can be obtained by using Table 2.A-1 of Appendix 2.A of the Phase I FLAG Report. These factors (a RH factor for each hour of RH) were then used to determine the average RH factor for that day (24 hour period). All of this was accomplished with the use of the CALPOST post-processor.

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 5-4 summarizes the IWAQM Phase II recommendations. The methodology in Table 5-4 was 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 was made to calculate regional haze based on the appropriate available data/resources. Specifically, regional haze was calculated using Method 2, which consists of computing extinctions from speciated PM measurements using hourly RH adjustments for observed and modeled sulfate and nitrates, which will be zero. The RH was capped at 95 percent. While this process occurs within CALPOST, a typical calculation methodology is illustrated below.

Table 5-4 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 hour SO ₄ , PM ₁₀ , and NO ₃ value; compute a day-average RH factor (f(RH)) for the worst day for the predicted species, 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 <i>IWAQM Phase II Summary Report and Recommendations for Modeling Long Range Transport Impacts</i> (EPA, 12/98).	

Calculation

Refined impacts will be calculated as follows:

1. Obtain 24 hour SO₄, NO₃, and PM speciated (EC and OC) impacts, in units of micrograms per cubic meter (µg/m³).
2. Convert the SO₄ impact to (NH₄)₂SO₄ by the following formula:

$$(NH_4)_2SO_4 (\mu g/m^3) = SO_4 (\mu g/m^3) \times \text{molecular weight } (NH_4)_2SO_4 / \text{molecular weight } SO_4$$

$$(NH_4)_2SO_4 (\mu g/m^3) = SO_4 (\mu g/m^3) \times 132/96 = SO_4 (\mu g/m^3) \times 1.375$$
3. Convert the NO₃ impact to NH₄NO₃ by the following formula:

$$NH_4NO_3 (\mu g/m^3) = NO_3 (\mu g/m^3) \times \text{molecular weight } NH_4NO_3 / \text{molecular weight } NO_3$$

$$NH_4NO_3 (\mu g/m^3) = NO_3 (\mu g/m^3) \times 80/62 = NO_3 (\mu g/m^3) \times 1.29$$
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:

$$b_{extb} = 3.912 / \text{visual range (km)}$$
6. Compute the change in extinction coefficients:
in terms of dv:

$$dv = 10 \ln (1 + b_{exts} / b_{extb})$$
in terms of percent change of visibility:

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

Based on the predicted SO₄, NO₃, and speciated PM concentrations, the proposed Project's emissions were compared to a 5 percent change in light extinction of the background levels. This is equivalent to a change in dv of 0.5. As illustrated in Table 5-5, the regional haze results are less than the 5 percent change in extinction threshold for the CWA and, as such, no further analysis is necessary.

Table 5-5 Regional Haze Results				
Class I Area	Change in Extinction ^(a) (%)			Recommended Threshold (%)
	2001	2002	2003	
CWA	2.23	2.26	1.37	5
^(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 for CWA 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 SO₂, SO₄, NO_x, NO₃, and HNO₃ 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 SO₂ and SO₄ contribute sulfur mass, and SO₄, NO_x, HNO₃, and NO₃ 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 US FWS for Class I areas located east of the Mississippi River. The results of the deposition analysis for CWA are presented in Table 5-6. As illustrated in the table, the deposition results for the CWA 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/m³) at the CWA were calculated for NO_x, SO₂, and PM/PM₁₀ 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 5-7 presents the maximum results of the Class I analysis for the 3 year period that was modeled. As illustrated in the table, there are no impacts above the Class I SILs at the CWA and, as such, no further analysis is necessary.

**Table 5-6
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	
CWA	3.87E-04	5.14E-04	5.10E-04	6.06E-04	8.22E-04	7.64E-04	0.01

^(a)Includes both wet and dry deposition with SO₄, NO_x, HNO₃, and NO₃ contributing to the nitrogen mass.
^(b)Includes both wet and dry deposition with SO₂ and SO₄ contributing sulfur mass.
^(c)For all areas east of the Mississippi River.

**Table 5-7
Class I Significant Impact Levels Modeling Results**

Pollutant	Averaging Period	Model-Predicted Impact ^(a) (µg/m ³)	PSD Class I SIL ^(b) (µg/m ³)	Exceed SILs?
Chassahowitzka Wilderness Area				
NO _x	Annual	8.68E-04	0.10	NO
SO ₂	Annual	6.92E-04	0.08	NO
	24 Hour	9.39E-03	0.20	NO
	3 Hour	3.06E-02	1.0	NO
PM/PM ₁₀	Annual	2.90E-03	0.16	NO
	24 Hour	4.24E-02	0.32	NO

^(a)Model-predicted impacts are maximum predicted impacts for the 3 year period of 2001, 2002, and 2003.
^(b)Class I SILs are calculated as 4 percent of the PSD Class I Increment values.

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 the CWA 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

The proposed Project will be located within the CIPP in Osceola County, Florida, which is approximately 20 miles southwest of Orlando, 5 miles west of Kissimmee, and 1 mile northwest of Intercession City. The proposed Project will occupy approximately 9 acres of the existing site. The site was previously zoned for agricultural use, but was approved for industrial use in 1993. Osceola County future land use maps indicate no change in the anticipated zoning pattern for the Power Park site or the adjacent land area in the future, confirming that the Power Park site will continue to be compatible with the predominant land use in the immediate project vicinity.

The two major cities in Osceola County are Kissimmee and St. Cloud. The City of Kissimmee, the county seat, is 18 miles due south of Orlando. Well known for its year-round desirable climate and abundant recreational opportunities, Kissimmee covers roughly 17 square miles and has become the fourth fastest growing county in the United States. Its current population of 59,364 makes it the largest city in Osceola County although it is relatively small when compared to Florida's largest municipalities.

The population trends of Osceola 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 US Census Bureau estimated that Osceola County had a population of 41,700 persons in 1977. The population of Osceola County was estimated to be 235,153 in 2005 by the University of Florida's Florida

Housing Data Clearinghouse. Osceola County's population constituted roughly 1.3 percent of the estimated 2005 state population of 17,918,453. The Osceola County population increased by 36.3 percent between 2000 and 2005, compared to a 12.1 percent growth for Florida. The respective 1990 to 2000 growth rate was 60.1 percent for Osceola County compared to 23.5 percent at the state level. The 2005 population estimate given above is a growth of 464 percent since 1977.

Since 1977, Osceola 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 (Osceola 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 September 2007 Osceola County had a total employment of 126,946 persons. Employment figures by occupation are available for the Orlando-Kissimmee Metropolitan Statistical Area (MSA). This MSA includes not only Orlando and Kissimmee, but also towns from Osceola, Orange, Seminole, and Lake counties. As of May 2006, there were 1,019,280 people employed among all occupations within this MSA; the largest occupation category was in the office and administrative support occupation (191,350 or 18.8 percent). This category was followed by sales and related occupation (132,160 or 13.0 percent), and the food preparation and serving occupation (110,350 or 10.8 percent). Major employment sectors in the county included the leisure and hospitality sector (21.6 percent) as well as the trade, transportation and utilities sector (21.4 percent). Education and health services (11.1 percent), construction (9.0 percent), professional and business services (8.9 percent) also made up a significant portion of the Osceola County employment by industry in 2006.

Compared to the state, Osceola County had a relatively higher concentration of employment in the leisure and hospitality sector (21.6 percent versus 11.5 percent). The county was well below the state percentage in the professional and business services sector (8.9 percent versus the state's 17.1 percent), and education and health services (11.1 percent for the county versus 18.4 percent in the state).

County business data for Osceola County for 1977 show the total employment to be 10,538 persons. The largest occupational category was in the services division (3,782, or 35.9 percent). This category was followed by the retail trade division (2,307, or 21.9 percent) and the government division (1,731, or 16.4 percent). Other major employment divisions in the county included manufacturing (10.5 percent), wholesale trade (5.1 percent), finance, insurance, real estate (3.8 percent), construction (3.6), and transportation/communications/utilities (2.0 percent). Agriculture (0.8 percent) made up the remainder of the occupational categories.

6.2.1 Workforce Growth Associated with the Project

The proposed Project will require a substantial construction workforce during the 23 month construction period, scheduled to span the July 2009 through May 2011 time frame. During this period, an average of 160 direct craft construction workers and a total workforce (that also includes indirect craft workers, construction management, and local utility staff) average of 182 personnel are expected. The peak construction workforce is projected to occur during the fifteenth month of construction, when 280 direct craft workers, and a total of 313 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 Unit 4 is estimated at two. 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

According to the US Census Bureau, there were 89,902 occupied housing units in Osceola County in 2006; this was approximately 1.0 percent of the 8,533,419 units in the state. Osceola County's total number of housing units in 2006 grew by 52 percent in the 6 years between the 2000 census, when 72,293 units were reported. Approximately 82 percent of the 2006 housing units were built in 1980 or later, with 5.5 percent built before 1960. Approximately 69 percent of residents moved into units after 2000; nearly 91 percent have moved to their residence in 1990 or later. The Orlando-Kissimmee MSA had a total of 749,928 housing units in 2006 and this constituted 8.8 percent of the total state's overall units.

The housing unit stock around Orlando and Kissimmee is relatively young, reflecting the recent population growth. Approximately 68 percent of the housing stock in 2006 was built in 1980 or later, and only 10 percent of the housing units were built before 1960. Approximately 64 percent of the 2006 population moved into their housing unit in 2000 or later, and approximately 86 percent moved into the unit in 1990 or later.

Building activity for Osceola County has continued at a rapid pace during the recent past, as reflected in the number of housing unit building permits issued. According to the US Department of Housing and Urban Development, in 2006, a total of 8,006 permits were issued for the county, and this was equal to approximately 2.6 percent of the 2002 existing housing stock. During 2002 through 2006, the type of housing unit for which a building permit was issued was primarily for single family structures, although 5+ unit multi-family structures also comprised a significant percentage in 2002 (32 percent) and in other years.

6.3.1 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 Unit 4 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 CIPP site is considered, large metropolitan areas including Orlando, Tampa, and Melbourne are within commuting distance to the site, and a 100 mile radius includes cities like Saint Petersburg and Clearwater.

In addition to the previously discussed housing and rental stock, Orlando and Kissimmee offer a wide variety of temporary lodging, reflecting the area's status as a destination for recreational seekers. The Kissimmee Convention and Visitors' Bureau Web site lists 144 motels, inns, hotels, RV parks, and short-term apartments in the area. Given the expected population of the commuting workforce, the fact that during the 23 month construction period most workers will be onsite for less than the total

construction period, an abundance of hotel and other short-term lodging options, it is unlikely that a substantial number of the Unit 4 construction workforce would choose to relocate during the 23 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 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 Unit 4 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, Unit 4 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 stack emissions from the proposed Project. The model-predicted pollutant concentrations were compared to AAQS, which are designed to protect the public health, welfare, and the natural environment. These AAQS 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 AAQS, 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, AAQS 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 SO₂, PM/PM₁₀, NO_x, and CO are not only one or more orders of magnitude less than the applicable AAQS, 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 SO₂, PM/PM₁₀, NO_x, and CO will not significantly affect vegetation, soils, or wildlife.

The air quality impact to soils, vegetation, and wildlife from H₂SO₄ is also expected to be insignificant. There is no national or state air quality standard for H₂SO₄ to compare model-predicted impacts with, as a general measure of H₂SO₄'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 ULSFO) and that predicted SO₂ concentrations are orders of magnitude less than USEPA recommended screening concentrations, it is reasonable to assume that H₂SO₄ 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 NO₂ concentrations at which adverse growth effects or tissue injury occurred for the most sensitive vegetation are: 3,760 ug/m³ (4 hour averaging period), 564 ug/m³ (1 month averaging period), and 94 ug/m³ (1 year averaging period). Similarly, the most sensitive vegetation threshold for CO is given as 1,800,000 ug/m³ (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 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	3.63	3.760	No
	24 hour	1.62	564	No
	1 month	0.27	94	No
CO	1 hour	10.93	1,800,000 ^(c)	No
^(a)Impacts represent the highest first high model-predicted concentration from the operation of Unit 4 for all 5 years of meteorological data modeled at 100 percent load. ^(b)Thresholds are taken from EPA document, <i>A Screening Procedure for the Impacts of Air Pollution Sources on Plant, Soils, and Animals</i>. ^(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

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: Florida Municipal Power Agency	
2. Site Name: Cane Island Power Park	
3. Facility Identification Number: 0970043	
4. Facility Location... Street Address or Other Locator: 6075 Old Tampa Highway City: Intercession City County: Osceola Zip Code: 33848	
5. Relocatable Facility? ☐ Yes ☒ No	6. Existing Title V Permitted Facility? ☒ Yes ☐ No

Application Contact

1. Application Contact Name: Susan Schumann	
2. Application Contact Mailing Address... Organization/Firm: Florida Municipal Power Agency Street Address: 8553 Commodity Circle City: Orlando State: FL Zip Code: 32819	
3. Application Contact Telephone Numbers... Telephone: (407) 355-7767 ext. Fax: (407) 355-5794	
4. Application Contact Email Address: susan.schumann@fmpa.com	

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	3. PSD Number (if applicable):
2. Project Number(s):	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

Florida Municipal Power Agency (FMPA) is proposing to own and construct and Kissimmee Utility Authority (KUA) is proposing to operate a new natural gas-fired combined cycle combustion turbine (CCCT) (Unit 4) at the existing Cane Island Power Park (CIPP) located near Kissimmee, Florida. The proposed CIPP Unit 4 and supporting ancillary equipment will join the existing units (Units 1, 2, and 3) at the CIPP. The proposed Unit 4 is rated at approximately 300 MW (net), firing natural gas as the only fuel.

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Processing Fee
	Unit 4 – GE PG7241 FA Combustion Turbine	AC1A	\$7,500
	Diesel Engine Fire Pump	AC1A	NA
	Safe Shutdown Generator	AC1A	NA
	Mechanical Draft Cooling Tower	AC1A	NA

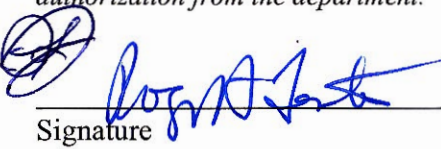
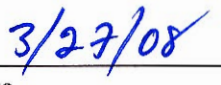
Application Processing Fee

Check one: ☒ 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 : Roger Fontes – General Manager and CEO
2. Owner/Authorized Representative Mailing Address... Organization/Firm: Florida Municipal Power Agency Street Address: 8553 Commodity Circle City: Orlando State: FL Zip Code: 32819
3. Owner/Authorized Representative Telephone Numbers... Telephone: (407) 355-7767 ext. Fax: (407) 355-5794
4. Owner/Authorized Representative Email Address: roger.fontes@fmpa.com
5. Owner/Authorized Representative Statement: <i>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.</i>  Signature  Date

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>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.</i> _____ Signature _____ Date

APPLICATION INFORMATION

Professional Engineer Certification

1. Professional Engineer Name: Stanley A. Armbruster, P.E. Registration Number: 30562
2. Professional Engineer Mailing Address... Organization/Firm: Black & Veatch Street Address: 11401 Lamar Avenue City: Overland Park State: KS Zip Code: 66211
3. Professional Engineer Telephone Numbers... Telephone: (913) 458-2763 ext. Fax: (913) 458-2934
4. Professional Engineer Email Address: ArmbrusterSA@bv.com
5. Professional Engineer Statement: <i>I, the undersigned, hereby certify, except as particularly noted herein*, that:</i> (1) <i>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</i> (2) <i>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.</i> (3) <i>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.</i> (4) <i>If the purpose of this application is to obtain an air construction permit (check here ☒, 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.</i> (5) <i>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.</i> Signature:  (seal)  Date: <u>April 1, 2008</u>

* 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) 447.5 North (km) 3128.0		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 Jay Butters
2. Facility Contact Mailing Address... Organization/Firm: Kissimmee Utility Authority Street Address: 6075 Old Tampa Highway City: Intercession City State: FL Zip Code: 33848
3. Facility Contact Telephone Numbers: Telephone: (407) 933-9853 ext. Fax: (407) 846-6485
4. Facility Contact Email Address: jbutters@kua.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]?
CO	A	N
NOX	A	N
PM	A	N
PM10	A	N
SO2	A	N
VOC	B	N
SAM	A	N

FACILITY INFORMATION

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'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:					

FACILITY INFORMATION

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) ☒ Attached, Document ID: <u>Attach. 1</u> ☐ 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) ☒ Attached, Document ID: <u>Attach. 2</u> ☐ 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) ☒ Attached, Document ID: <u>Attach. 3</u> ☐ Previously Submitted, Date: _____

Additional Requirements for Air Construction Permit Applications

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

FACILITY INFORMATION

C. FACILITY ADDITIONAL INFORMATION (CONTINUED)

Additional Requirements for FESOP Applications

- | |
|---|
| 1. List of Exempt Emissions Units:
☐ 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 Onsite 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 |

FACILITY INFORMATION

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)):

☒ Attached, Document ID: Attach. 7 ☐ 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)):

☒ Attached, Document ID: Attach. 7 ☐ Previously Submitted, Date: _____

☐ Not Applicable (not a CAIR source)

3. Hg Budget Part (DEP Form No. 62-210.900(1)(c)):

☒ Attached, Document ID: Attach. 7 ☐ 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 F of the application package.

EMISSIONS UNIT INFORMATION

Section [1] of [4]

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 an initial, revised or renewal 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. 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 an 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 or 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. A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit addressed in this application that is subject to air construction permitting and for each such emissions unit that is a regulated or unregulated unit for purposes of Title V permitting. (An emissions unit may be exempt from air construction permitting but still be classified as an unregulated unit for Title V purposes.) Emissions units classified as insignificant for Title V purposes 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.

EMISSIONS UNIT INFORMATION

Section [1] of [4]

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).
- ☐ 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: Unit 1 – GE PG7241 FA Combustion Turbine.

3. Emissions Unit Identification Number:

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

9. Package Unit:

Manufacturer: GE

Model Number: PG7241 FA

10. Generator Nameplate Rating: 157 MW for the CT

153 MW for the STG

Above ratings are gross output. When auxiliary power is subtracted, nominal rating is 300 MW net for the combined cycle unit.

11. Emissions Unit Comment: The combined cycle combustion turbine will include HRSG duct firing capability.

EMISSIONS UNIT INFORMATION

Section [1] of [4]

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description:
Dry low NO_x burners in conjunction with selective catalytic reduction will be used to control NO_x emissions when firing natural gas.

2. Control Device or Method Code(s): 205, 139

EMISSIONS UNIT INFORMATION

Section [1] of [4]

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: 1975.2 million Btu/hr (HHV) – CT firing natural gas 593.2 million Btu/hr (HHV) – Duct Burner firing natural gas		
4. Maximum Incineration Rate: pounds/hr tons/day		
5. Requested Maximum Operating Schedule:		
CT firing natural gas	24 hours/day	7 days/week
	52 weeks/year	8,760 hours/year
Duct burner firing natural gas	24 hours/day	7 days/week
	52 weeks/year	8,760 hours/year
6. Operating Capacity/Schedule Comment: The unit will be operated between 40 and 100 percent of full load. The maximum heat input rate shown in Field 3 is with operation at 100% load at the site minimum ambient temperature of 19°F. Operation at 100 percent load and a 59°F (ISO conditions) is expected to have a corresponding maximum heat input of 1,860.4 MBtu/hr (HHV). Note that the heat input rate is a function of ambient temperature. We request inclusion of the standard permitting note that the heat input rates are provided for informational purposes only and are not intended to be enforceable limits.		

EMISSIONS UNIT INFORMATION

Section [1] of [4]

**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: Heat Recovery Steam Generator Exhaust Stack		2. Emission Point Type Code: 1	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:			
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:			
5. Discharge Type Code: V	6. Stack Height: 160 feet	7. Exit Diameter: 18 feet	
8. Exit Temperature: 167°F	9. Actual Volumetric Flow Rate: 990,556 acfm	10. Water Vapor: 11%	
11. Maximum Dry Standard Flow Rate: 819,771 scfm		12. Nonstack Emission Point Height:	
13. Emission Point UTM Coordinates... Zone: 17 East (km): 447.6239 North (km): 3127.9624		14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)	
15. Emission Point Comment: Emission point information given in Fields 8 through 11 are based on firing natural gas in the CTG and the duct burner with operation at 100% load, evaporative cooler on, and at ISO Conditions			

EMISSIONS UNIT INFORMATION

Section [1] of [4]

D. SEGMENT (PROCESS/FUEL) INFORMATION**Segment Description and Rate:** Segment 1 of 2

1. Segment Description (Process/Fuel Type): Natural gas used in the combustion turbine			
2. Source Classification Code (SCC): 20100201		3. SCC Units: Million Cubic Feet Burned	
4. Maximum Hourly Rate: 2.03	5. Maximum Annual Rate: 17,838	6. Estimated Annual Activity Factor:	
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: 970 (HHV)	
10. Segment Comment: The maximum fuel input to the combustion turbine is a function of the ambient temperature. The maximum hourly rate given in Field 4 is based on operation at 100% load at the site minimum ambient temperature of 19°F. The maximum natural gas use rate given in Field 5 is based on 100 percent load operation for 8,760 hours per year at the site minimum ambient temperature of 19°F. The fuel use rates do not include duct burner. See next segment for duct burner. operation.			

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type): Natural gas used in duct burner.			
2. Source Classification Code (SCC):		3. SCC Units: Million Cubic Feet Burned	
4. Maximum Hourly Rate: 0.61	5. Maximum Annual Rate: 5,357	6. Estimated Annual Activity Factor:	
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: 970 (HHV)	
10. Segment Comment: The duct burner is fired only with natural gas.			

EMISSIONS UNIT INFORMATION

Section [1] of [4]

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
CO			
NOX	205, 139 (NG)		EL
PM			
PM10			
SO2			WP
VOC			
SAM			WP

**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 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: 40.8 lb/hour 178.70 tons/year		4. Synthetically Limited? ☐ Yes ☒ No	
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year			
6. Emission Factor: Reference: Vendor Data		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: Potential emissions are based on vendor data. The potential hourly CO emissions are based on operation in combined cycle mode firing natural gas in the combustion turbine at 100% load, evaporative cooler on, firing natural gas in the duct burner and operation at ISO Conditions. Annual emissions = (40.8 lb/hr x 8,760 hr/yr) x 1 ton/2,000 lb = 178.70 tons/year			
11. Potential, Fugitive, and Actual Emissions Comment: The potential hourly and annual emissions are for informational purposes only and do not constitute emission 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/ESTIMATED FUGITIVE EMISSIONS**

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete 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: 17.6 lb/hour 77.09 tons/year	4. Synthetically Limited? ☐ Yes ☒ No	
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year		
6. Emission Factor: Reference: Vendor Data	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: Potential emissions are based on vendor data. The potential hourly NO _x emissions are based on operation in combined cycle mode firing natural gas in the combustion turbine at 100% load, evaporative cooler on, firing natural gas in the duct burner and operation at ISO Conditions. Annual emissions = (17.6 lb/hr x 8,760 hr/yr) x 1 ton/2,000 lb = 77.09 tons/year		
11. Potential, Fugitive, and Actual Emissions Comment: The potential hourly and annual emissions are for informational purposes only and do not constitute emission 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: RULE	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 15 ppmvd	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: CEMS	
6. Allowable Emissions Comment (Description of Operating Method): The allowable emissions level in Field 3 is from NSPS Subpart KKKK and applies when Unit 4 is operating on natural gas at greater than 75 percent load. Equivalent allowable emissions are based on operation at 59°F ambient temperature (ISO) 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: 2.0 ppmvd at 15% O ₂ (combined cycle mode with natural gas firing)	4. Equivalent Allowable Emissions: 17.6 lb/hour 77.09 tons/year
5. Method of Compliance: CEMS.	
6. Allowable Emissions Comment (Description of Operating Method): The allowable emissions rate given in Field 3 is based on the BACT analysis provided with this application. Equivalent allowable emission rates are given for informational purposes only and do not represent limits. The equivalent allowable hourly and annual emissions rates are based on operation at 100% load and at ISO conditions. The equivalent allowable emissions include emissions from HRSG duct burner firing. The allowable emissions from 40 CFR 60, Subpart KKKK are 0.39 lb/MW-hr when firing natural gas, based on a 4-hour rolling average. Compliance with the BACT levels will ensure compliance with the standard.	

**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL/ESTIMATED FUGITIVE EMISSIONS**

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete 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: 39.7 lb/hour 173.89 tons/year	4. Synthetically Limited? ☐ Yes ☐ No	
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year		
6. Emission Factor: Reference: Vendor Data	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: Potential emissions are based on vendor data. The potential hourly PM/PM10 emissions are based on operation in combined cycle mode firing natural gas in the combustion turbine at 100% load, evaporative cooler on, firing natural gas in the duct burner and operation at ISO Conditions. Annual emissions = (39.7 lb/hr x 8,760 hr/yr) x 1 ton/2,000 lb = 173.89 tons/year		
11. Potential, Fugitive, and Actual Emissions Comment: The potential hourly and annual emissions are for informational purposes only and do not constitute emission 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/ESTIMATED FUGITIVE EMISSIONS**

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete 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: SO ₂	2. Total Percent Efficiency of Control:	
3. Potential Emissions: 10.34 lb/hour 45.29 tons/year		4. Synthetically Limited? ☐ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year		
6. Emission Factor: Reference: Vendor Data	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: Potential emissions are based on vendor data. The potential hourly SO ₂ emissions are based on operation in combined cycle mode firing natural gas in the combustion turbine at 100% load, evaporative cooler on, firing natural gas in the duct burner and operation at ISO Conditions. Annual emissions = (10.34 lb/hr x 8,760 hr/yr) x 1 ton/2,000 lb = 45.29 tons/year		
11. Potential, Fugitive, and Actual Emissions Comment: The potential hourly and annual emissions are for informational purposes only and do not constitute emission 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: RULE	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: Natural gas with less than 20 grains per 100 scf of natural gas	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, FMPS 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 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 2 grains sulfur per 100 scf in the natural gas	4. Equivalent Allowable Emissions: 10.34 lb/hour 45.29 tons/year
5. Method of Compliance: Compliance will be demonstrated by keeping reports obtained from the vendor indicating the average sulfur content of the natural gas supplied from the pipeline for each month of operation.	
6. Allowable Emissions Comment (Description of Operating Method): The allowable emissions standard given in Field 3 is based on the BACT analysis provided with this application. Equivalent allowable emission rates are given for informational purposes only and do not represent limits. The equivalent allowable hourly and annual emissions rate is based on operation at 100% load in combined cycle mode, evaporative cooler on, duct firing and at ISO conditions. While the natural gas tariff does not guarantee a sulfur content of 2 grains per 100 scf, historical data indicates that this is a reasonable sulfur level. Therefore, if the permit is to include a natural gas sulfur content standard, it is requested that any such standard be based on a calendar month average.	

EMISSIONS UNIT INFORMATION

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POLLUTANT DETAIL INFORMATION

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**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL/ESTIMATED FUGITIVE EMISSIONS****(Optional for unregulated emissions units.)****Potential/Estimated Fugitive Emissions**

Complete 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: 5.3 lb/hour 23.21 tons/year		4. Synthetically Limited? ☐ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year		
6. Emission Factor: Reference: Vendor Data	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: Potential emissions are based on vendor data. The potential hourly VOC emissions are based on operation in combined cycle mode firing natural gas in the combustion turbine at 100% load, evaporative cooler on, firing natural gas in the duct burner and operation at ISO Conditions. Annual emissions = (5.3 lb/hr x 8,760 hr/yr) x 1 ton/2,000 lb = 23.21 tons/year		
11. Potential, Fugitive, and Actual Emissions Comment: The potential hourly and annual emissions are for informational purposes only and do not constitute emission 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/ESTIMATED FUGITIVE EMISSIONS**

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete 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: 5.54 lb/hour 24.27 tons/year		4. Synthetically Limited? ☐ Yes ☐ No	
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year			
6. Emission Factor: Reference: Vendor Data		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: Potential emissions are based on vendor data. The potential hourly SAM emissions are based on operation in combined cycle mode firing natural gas in the combustion turbine at 100% load, evaporative cooler on, firing natural gas in the duct burner and operation at ISO Conditions. Annual emissions = (5.54 lb/hr x 8,760 hr/yr) x 1 ton/2,000 lb = 24.27 tons/year			
11. Potential, Fugitive, and Actual Emissions Comment: The potential hourly and annual emissions are for informational purposes only and do not constitute emission 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 1

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 2 grains sulfur per 100 scf in the natural gas	4. Equivalent Allowable Emissions: 5.54 lb/hour 24.27 tons/year
5. Method of Compliance: Fuel supplier tariff sheet	
6. Allowable Emissions Comment (Description of Operating Method): The allowable emissions rate given in Field 3 is based on the BACT analysis provided with this application. Equivalent allowable emission rates are based on the estimated oxidation of SO ₂ to SO ₃ and assuming 100 percent conversion of SO ₃ to sulfuric acid mist. Equivalent allowable emissions are given for informational purposes only and do not represent limits. They are based on operation in combined cycle mode firing natural gas in the combustion turbine at 100% load, evaporative cooler on, firing natural gas in the duct burner and operation at ISO Conditions.	

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):	

EMISSIONS UNIT INFORMATION

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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:	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:	

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:	

EMISSIONS UNIT INFORMATION

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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:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: To be determined Model Number: To be determined Serial Number: To be determined	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: CEMS will be installed before operation of the emission source. CEMS is required as a condition of 40 CFR Parts 60 and 75.	

Continuous Monitoring System: Continuous Monitor 2 of 2

1. Parameter Code: CO2 or O2	2. Pollutant(s):
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: To be determined Model Number: To be determined Serial Number: To be determined	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: CEMS will be installed before operation of the emission source. CEMS is required as a condition of 40 CFR 75.	

EMISSIONS UNIT INFORMATION

Section [1] of [4]

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:	

EMISSIONS UNIT INFORMATION

Section [1] of [4]

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:	

EMISSIONS UNIT INFORMATION

Section [1] of [4]

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) ☒ Attached, Document ID: <u>Attach. 2</u> ☐ 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) ☒ Attached, Document ID: <u>See Application Support Document</u> .
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: <u>see Section 3 in Application Support Document</u>
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 _____ ☒ 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) ☒ Attached, Document ID: <u>Attach. 5</u> ☐ 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: _____ ☒ 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: _____ ☒ Not Applicable

EMISSIONS UNIT INFORMATION

Section [1] of [4]

I. EMISSIONS UNIT ADDITIONAL INFORMATION (CONTINUED)**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)) ☒ Attached, Document ID: <u>See Section 3 of the Application Support Document</u>
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.) ☒ Attached, Document ID: <u>See Section 4 of the Application Support Document</u>
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only) ☒ Attached, Document ID: <u>Attach.6</u> ☐ 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 F of the application package.

EMISSIONS UNIT INFORMATION

Section [2] of [4]

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).
- ☐ 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: 290 BHP Diesel Engine Fire Pump.

3. Emissions Unit Identification Number:

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

Manufacturer: TBD

Model Number: TBD

10. Generator Nameplate Rating:

11. Emissions Unit Comment:

EMISSIONS UNIT INFORMATION

Section [2] of [4]

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description:

2. Control Device or Method Code(s):

EMISSIONS UNIT INFORMATION

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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: 290 HP (approximate)
3. Maximum Heat Input Rate:
4. Maximum Incineration Rate: pounds/hr tons/day
5. Requested Maximum Operating Schedule:
6. Operating Capacity/Schedule Comment: Based on National Fire Protection Association (NFPA) guidelines it is conservatively estimated that the diesel engine fire pump will operate approximately 52 hours per year. Because this is emergency fire equipment, a maximum operating schedule is not requested. Because a specific manufacturer and model has not been determined, the maximum production rate provided is an approximate value.

EMISSIONS UNIT INFORMATION

Section [2] of [4]

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: Fire Pump Building		2. Emission Point Type Code: 1	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:			
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:			
5. Discharge Type Code: V	6. Stack Height: 15.17 feet		7. Exit Diameter: 0.4167 feet
8. Exit Temperature: 855°F	9. Actual Volumetric Flow Rate: 1,506 acfm		10. Water Vapor: %
11. Maximum Dry Standard Flow Rate:		12. Nonstack Emission Point Height:	
13. Emission Point UTM Coordinates... Zone: 17 East (km): 447.589 North (km): 3127.965		14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)	
15. Emission Point Comment: The above information is based on preliminary vendor information and represents the expected approximate emission unit parameters.			

EMISSIONS UNIT INFORMATION

Section [2] of [4]

D. SEGMENT (PROCESS/FUEL) INFORMATION**Segment Description and Rate:** Segment 1 of 1

1. Segment Description (Process/Fuel Type): ULSFO used in the diesel engine fire pump			
2. Source Classification Code (SCC): 20100301		3. SCC Units: Thousand Gallons Burned	
4. Maximum Hourly Rate: 0.0135	5. Maximum Annual Rate: 2.7	6. Estimated Annual Activity Factor:	
7. Maximum % Sulfur: 0.0015	8. Maximum % Ash:	9. Million Btu per SCC Unit: 137 (HHV)	
10. Segment Comment: The above information is based on preliminary vendor information and represents the expected approximate emission unit parameters. The annual rate is based on an estimated 52 hours per year of operation.			

Segment Description and Rate: Segment of

1. Segment Description (Process/Fuel Type):			
2. Source Classification Code (SCC):		3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:	
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:	
10. Segment Comment:			

EMISSIONS UNIT INFORMATION

Section [2] of [4]

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
CO			NS
NOX			EL
PM			EL
PM10			NS
SO2			NS
VOC			EL

**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL/ESTIMATED FUGITIVE EMISSIONS**

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete 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: 0.33 lb/hour 8.48 E-03 tons/year		4. Synthetically Limited? ☒ Yes ☐ No	
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year			
6. Emission Factor: Reference: Vendor Data		7. Emissions Method Code: 5	
8. Calculation of Emissions: Potential emissions are based on vendor data. The maximum hourly CO emission rate is 0.33 lb/hour. The maximum annual potential CO emissions are based on operating 52 hours per year. Annual emissions = 0.33 lb/hr x 52 hours/year x 1 ton/2,000 lb = 8.48 E-03 tons/year			
9. Pollutant Potential/Estimated Fugitive Emissions Comment: The potential emissions are estimates based on preliminary vendor data. The potential emissions are given for informational purposes and do not represent limits.			

**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS**

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

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions:
5. Method of Compliance: Manufacturer certification	
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/ESTIMATED FUGITIVE EMISSIONS**

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete 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: 1.92 lb/hour 4.99 E-02 tons/year		4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year		
6. Emission Factor: Reference: Vendor Data		7. Emissions Method Code: 5
8. Calculation of Emissions: Potential emissions are based on vendor data. The maximum hourly NO _x emission rate is 1.92 lb/hour. The maximum annual potential NO _x emissions are based on operating 52 hours per year. Annual emissions = 1.92 lb/hr x 52 hours/year x 1 ton/2,000 lb = 4.99 E-02 tons/year		
9. Pollutant Potential/Estimated Fugitive Emissions Comment: The potential NO _x emissions are based on the NSPS Subpart IIII 2009 model year limit for NO _x + non-methane HC of 3 g/hp-hr. As a worst case NO _x emissions were assumed to be 3 g/hp-hr. The potential emissions are given for informational purposes and do not represent 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 1

1. Basis for Allowable Emissions Code: RULE – NSPS Subpart IIII	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 3 g/hp-hr (NOX + NMHC) for 2009 model year engines	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: Manufacturer certification	
6. Allowable Emissions Comment (Description of Operating Method): Based on the NSPS, compliance will be certified by the manufacturer and no emissions testing is required.	

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/ESTIMATED FUGITIVE EMISSIONS**

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete 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: 0.08 lb/hour 2.16 E-03 tons/year		4. Synthetically Limited? ☒ Yes ☐ No	
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year			
6. Emission Factor: Reference: Vendor Data		7. Emissions Method Code: 5	
8. Calculation of Emissions: Potential emissions are based on vendor data. The maximum hourly PM/PM10 emission rate is 0.083 lb/hour. The maximum annual potential PM emissions are based on operating 52 hours per year. Annual emissions = 0.083 lb/hr x 52 hours/year x 1 ton/2,000 lb = 2.16 E-03 tons/year			
9. Pollutant Potential/Estimated Fugitive Emissions Comment: The potential emissions are estimates based on preliminary vendor data. The potential emissions are given for informational purposes and do not represent 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 1

1. Basis for Allowable Emissions Code: RULE – NSPS Subpart IIII	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 0.15 g/hp-hr	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: Manufacturer certification	
6. Allowable Emissions Comment (Description of Operating Method): Based on the NSPS, compliance will be certified by the manufacturer and no emissions testing is required.	

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/ESTIMATED FUGITIVE EMISSIONS**

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete 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: SO ₂	2. Total Percent Efficiency of Control:	
3. Potential Emissions: 0.0029 lb/hour 7.42 E-05 tons/year		4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year		
6. Emission Factor: Reference: Vendor Data		7. Emissions Method Code: 5
8. Calculation of Emissions: Potential emissions are based on vendor data using fuel oil with 0.0015 percent sulfur content. The maximum hourly SO ₂ emission rate is 0.003 lb/hour. The maximum annual potential SO ₂ emissions are based on operating 52 hours per year. Annual emissions = 0.003 lb/hr x 52 hours/year x 1 ton/2,000 lb = 7.42 E-05 tons/year		
9. Pollutant Potential/Estimated Fugitive Emissions Comment: Potential emissions shown in Fields 3 and 8 are based on using fuel oil with 0.0015 percent sulfur content. The potential emissions are estimates based on preliminary vendor data. The potential emissions are given for informational purposes and do not represent 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):	

**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL/ESTIMATED FUGITIVE EMISSIONS**

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete 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: 0.66 lb/hour 1.72E-02 tons/year		4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year		
6. Emission Factor: Reference: Vendor Data		7. Emissions Method Code: 5
8. Calculation of Emissions: Potential emissions are based on vendor data. The maximum hourly VOC emission rate is 0.19 lb/hour. The maximum annual potential VOC emissions are based on operating 52 hours per year. Annual emissions = 0.66 lb/hr x 52 hours/year x 1 ton/2,000 lbs = 1.72 E-02 tons/year		
9. Pollutant Potential/Estimated Fugitive Emissions Comment: The potential emissions are estimates based on preliminary vendor data. The potential emissions are given for informational purposes and do not represent 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 1

1. Basis for Allowable Emissions Code: RULE- NSPS Subpart IIII	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 3 g/hp-hr (NOX + NMHC)	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: Manufacturer certification	
6. Allowable Emissions Comment (Description of Operating Method): Based on the NSPS, compliance will be certified by the manufacturer and no emissions testing is required.	

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):	

EMISSIONS UNIT INFORMATION

Section [2] of [4]

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:	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:	

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:	

EMISSIONS UNIT INFORMATION

Section [2] of [4]

H. CONTINUOUS MONITOR INFORMATION

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:	

EMISSIONS UNIT INFORMATION

Section [2] of [4]

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) ☐ Attached, Document ID: _____ ☐ 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) ☒ Attached, Document ID: <u>See Application Support Document</u>
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: _____ ☐ Previously Submitted, Date _____
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 _____ ☒ 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) ☒ Attached, Document ID: <u>Attach. 5</u> ☐ 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: _____ _____ ☒ 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: _____ ☒ Not Applicable

Section [2] of [4]

1. Control Technology Review and Analysis (Rules 62-212.400(6) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e))	☒ Attached, Document ID: <u>See Section 3 of Application Support Document</u>
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(5)(h)6., F.A.C., and Rule 62-212.500(4)(f), F.A.C.)	☒ Attached, Document ID: <u>See Section 4 of Application Support Document</u>
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only)	☐ Attached, Document ID: _____ ☒ Not Applicable

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

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EMISSIONS UNIT INFORMATION

Section [3] of [4]

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).

☐ 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: Safe Shutdown Generator.

3. Emissions Unit Identification Number:

4. Emissions
Unit Status
Code:
C

5. Commence
Construction
Date:

6. Initial
Startup
Date:

7. Emissions Unit
Major Group
SIC Code:
49

8. Acid Rain Unit?
☐ Yes
☒ No

9. Package Unit:

Manufacturer: TBD

Model Number: TBD

10. Generator Nameplate Rating: 750 kW standby rating

11. Emissions Unit Comment:

EMISSIONS UNIT INFORMATION

Section [3] of [4]

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description:

2. Control Device or Method Code(s):

EMISSIONS UNIT INFORMATION

Section [3] of [4]

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: 1,102 HP (approximate)
3. Maximum Heat Input Rate:
4. Maximum Incineration Rate: pounds/hr tons/day
5. Requested Maximum Operating Schedule:
6. Operating Capacity/Schedule Comment: It is conservatively estimated that the safe shutdown generator will operate approximately 200 hours per year. Because this is emergency equipment, a maximum operating schedule is not requested. Because a specific manufacturer and model has not been determined, the maximum production rate provided is an approximate value.

EMISSIONS UNIT INFORMATION

Section [3] of [4]

**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: Safe Shutdown Generator		2. Emission Point Type Code: 1	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:			
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:			
5. Discharge Type Code: V	6. Stack Height: 24 feet		7. Exit Diameter: 0.83 feet
8. Exit Temperature: 816°F	9. Actual Volumetric Flow Rate: 6,310 acfm		10. Water Vapor: %
11. Maximum Dry Standard Flow Rate:		12. Nonstack Emission Point Height:	
13. Emission Point UTM Coordinates... Zone: 17 East (km): 447.623 North (km): 3128.018		14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)	
15. Emission Point Comment: The above information is based on preliminary vendor information and represents the expected approximate emission unit parameters.			

EMISSIONS UNIT INFORMATION

Section [3] of [4]

D. SEGMENT (PROCESS/FUEL) INFORMATION**Segment Description and Rate:** Segment 1 of 1

1. Segment Description (Process/Fuel Type): ULSFO used in the safe shutdown generator		
2. Source Classification Code (SCC): 20100301		3. SCC Units: Thousand Gallons Burned
4. Maximum Hourly Rate: 0.15	5. Maximum Annual Rate: 30	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: 137 (HHV)
10. Segment Comment: The above information is based on preliminary vendor information and represents the expected approximate emission unit parameters. The annual rate is based on an estimated 200 hours per year of operation.		

Segment Description and Rate: Segment of

1. Segment Description (Process/Fuel Type):		
2. Source Classification Code (SCC):		3. SCC Units:
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment:		

EMISSIONS UNIT INFORMATION

Section [3] of [4]

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
CO			EL
NOX			EL
PM			EL
PM10			NS
SO2			NS
VOC			EL

**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL/ESTIMATED FUGITIVE EMISSIONS**

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete 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: 1.11 lb/hour 0.11 tons/year		4. Synthetically Limited? ☒ Yes ☐ No	
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year			
6. Emission Factor: Reference: Vendor Data		7. Emissions Method Code: 5	
8. Calculation of Emissions: Potential emissions are based on vendor data. The maximum hourly CO emission rate is 1.11 lb/hour. The maximum annual potential CO emissions are based on operating 200 hours per year. Annual emissions = 1.11 lb/hr x 200 hours/year x 1 ton/2,000 lb = 0.11 tons/year			
9. Pollutant Potential/Estimated Fugitive Emissions Comment: The potential emissions are estimates based on preliminary vendor data. The potential emissions are given for informational purposes and do not represent 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 1

1. Basis for Allowable Emissions Code: RULE - NSPS Subpart IIII	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 2.6 g/hp-hr	4. Equivalent Allowable Emissions:
5. Method of Compliance: Manufacturer certification	
6. Allowable Emissions Comment (Description of Operating Method): Based on the NSPS, compliance will be certified by the manufacturer and no emissions testing is required.	

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/ESTIMATED FUGITIVE EMISSIONS**

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete 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: 9.64 lb/hour 0.96 tons/year	4. Synthetically Limited? ☒ Yes ☐ No	
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year		
6. Emission Factor: Reference: Vendor Data		7. Emissions Method Code: 5
8. Calculation of Emissions: Potential emissions are based on vendor data. The maximum hourly NO _x emission rate is 9.64 lb/hour. The maximum annual potential NO _x emissions are based on operating 200 hours per year. Annual emissions = 9.64 lb/hr x 200 hours/year x 1 ton/2,000 lb = 0.96 tons/year		
9. Pollutant Potential/Estimated Fugitive Emissions Comment: The potential emissions are estimates based on preliminary vendor data. The potential emissions are given for informational purposes and do not represent 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 1

1. Basis for Allowable Emissions Code: RULE – NSPS Subpart IIII	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 4.8 g/hp-hr (NOX + NMHC)	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: Manufacturer certification	
6. Allowable Emissions Comment (Description of Operating Method): Based on the NSPS, compliance will be certified by the manufacturer and no emissions testing is required.	

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/ESTIMATED FUGITIVE EMISSIONS**

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete 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: 0.29 lb/hour 0.029 tons/year	4. Synthetically Limited? ☒ Yes ☐ No	
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year		
6. Emission Factor: Reference: Vendor Data		7. Emissions Method Code: 5
8. Calculation of Emissions: Potential emissions are based on vendor data. The maximum hourly PM/PM10 emission rate is 0.29 lb/hour. The maximum annual potential PM emissions are based on operating 200 hours per year. Annual emissions = 0.29 lb/hr x 200 hours/year x 1 ton/2,000 lb = 0.029 tons/year		
9. Pollutant Potential/Estimated Fugitive Emissions Comment: The potential emissions are estimates based on preliminary vendor data. The potential emissions are given for informational purposes and do not represent 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 1

1. Basis for Allowable Emissions Code: RULE – NSPS Subpart IIII	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 0.15 g/hp-hr	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: Manufacturer certification	
6. Allowable Emissions Comment (Description of Operating Method): Based on the NSPS, compliance will be certified by the manufacturer and no emissions testing is required.	

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/ESTIMATED FUGITIVE EMISSIONS**

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete 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: SO ₂	2. Total Percent Efficiency of Control:	
3. Potential Emissions: 0.011 lb/hour 0.0011 tons/year	4. Synthetically Limited? ☒ Yes ☐ No	
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year		
6. Emission Factor: Reference: Vendor Data		7. Emissions Method Code: 5
8. Calculation of Emissions: Potential emissions are based on vendor data using fuel oil with 0.0015 percent sulfur content. The maximum hourly SO ₂ emission rate is 0.11 lb/hour. The maximum annual potential SO ₂ emissions are based on operating 200 hours per year. Annual emissions = 0.11 lb/hr x 200 hours/year x 1 ton/2,000 lb = 0.0011 tons/year		
9. Pollutant Potential/Estimated Fugitive Emissions Comment: Potential emissions shown in Fields 3 and 8 are based on using fuel oil with 0.0015 percent sulfur content. The potential emissions are estimates based on preliminary vendor data. The potential emissions are given for informational purposes and do not represent 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):	

**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL/ESTIMATED FUGITIVE EMISSIONS**

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete 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: 0.66 lb/hour 0.066 tons/year	4. Synthetically Limited? ☐ Yes ☒ No	
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year		
6. Emission Factor: Reference: Vendor Data		7. Emissions Method Code: 5
8. Calculation of Emissions: Potential emissions are based on vendor data. The maximum hourly VOC emission rate is 0.66 lb/hour. The maximum annual potential VOC emissions are based on operating 200 hours per year. Annual emissions = 0.66 lb/hr x 200 hours/year x 1 ton/2,000 lbs = 0.066 tons/year		
9. Pollutant Potential/Estimated Fugitive Emissions Comment: The potential emissions are estimates based on preliminary vendor data. The potential emissions are given for informational purposes and do not represent 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 1

1. Basis for Allowable Emissions Code: RULE- NSPS Subpart IIII	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 4.8 g/hp-hr (NOX + NMHC)	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: Manufacturer certification	
6. Allowable Emissions Comment (Description of Operating Method): Based on the NSPS, compliance will be certified by the manufacturer and no emissions testing is required.	

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):	

EMISSIONS UNIT INFORMATION

Section [3] of [4]

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:	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:	

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:	

EMISSIONS UNIT INFORMATION

Section [3] of [4]

H. CONTINUOUS MONITOR INFORMATION

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:	

EMISSIONS UNIT INFORMATION

Section [3] of [4]

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) ☐ Attached, Document ID: _____ ☐ 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) ☒ Attached, Document ID: <u>See Application Support Document</u>
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: _____ ☐ Previously Submitted, Date _____
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 _____ ☒ 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) ☒ Attached, Document ID: <u>Attach. 5</u> ☐ 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: _____ _____ ☒ 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: _____ ☒ Not Applicable

Section [3] of [4]

1. Control Technology Review and Analysis (Rules 62-212.400(6) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e))	☒ Attached, Document ID: <u>See Section 3 of Application Support Document</u>
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(5)(h)6., F.A.C., and Rule 62-212.500(4)(f), F.A.C.)	☒ Attached, Document ID: <u>See Section 4 of Application Support Document</u>
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only)	☐ Attached, Document ID: _____ ☒ Not Applicable

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

[illegible]

EMISSIONS UNIT INFORMATION

Section [4] of [4]

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).
- ☐ 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: Mechanical Draft Cooling Tower.

3. Emissions Unit Identification Number:

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

9. Package Unit:
Manufacturer:

Model Number:

10. Generator Nameplate Rating:

11. Emissions Unit Comment:

EMISSIONS UNIT INFORMATION

Section [4] of [4]

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description: Drift eliminators

2. Control Device or Method Code(s): 152

EMISSIONS UNIT INFORMATION

Section [4] of [4]

B. EMISSIONS UNIT CAPACITY INFORMATION**(Optional for unregulated emissions units.)****Emissions Unit Operating Capacity and Schedule**

1. Maximum Process or Throughput Rate: 111,130 gpm design water flow
2. Maximum Production Rate:
3. Maximum Heat Input Rate:
4. Maximum Incineration Rate: pounds/hr tons/day
5. Requested Maximum Operating Schedule: 24 hours/day 7 days/week 52 weeks/year 8,760 hours/year
6. Operating Capacity/Schedule Comment:

EMISSIONS UNIT INFORMATION

Section [4] of [4]

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: Cooling Tower		2. Emission Point Type Code: 3	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:			
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:			
5. Discharge Type Code: V	6. Stack Height: 56 ft		7. Exit Diameter: 30 ft
8. Exit Temperature: 91.52 F	9. Actual Volumetric Flow Rate: 1,003,756 acfm	10. Water Vapor: %	
11. Maximum Dry Standard Flow Rate:		12. Nonstack Emission Point Height:	
13. Emission Point UTM Coordinates... Zone: 17 East (km): 447.516 North (km): 3128.009		14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)	
15. Emission Point Comment: The cooling tower design is an 8 cell mechanical draft cooling tower. The information given in fields 5 through 9 is for each cell.			

EMISSIONS UNIT INFORMATION

Section [4] of [4]

D. SEGMENT (PROCESS/FUEL) INFORMATION**Segment Description and Rate:** Segment 1 of 1

1. Segment Description (Process/Fuel Type): Drift loss			
2. Source Classification Code (SCC): 38500101		3. SCC Units: Thousand Gallons Transferred or Handled	
4. Maximum Hourly Rate: 6,670	5. Maximum Annual Rate: 58,409,928	6. Estimated Annual Activity Factor:	
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:	
10. Segment Comment: The maximum hourly and annual rates shown in Fields 4 and 5 are the design water circulation rate.			

Segment Description and Rate: Segment __ of __

1. Segment Description (Process/Fuel Type):			
2. Source Classification Code (SCC):		3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:	
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:	
10. Segment Comment:			

EMISSIONS UNIT INFORMATION

Section [4] of [4]

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
PM			WS
PM10			WS

**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL/ESTIMATED FUGITIVE EMISSIONS**

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete 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: 0.66 lb/hour 2.89 tons/year	4. Synthetically Limited? ☐ Yes ☒ No	
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year		
6. Emission Factor: Reference: Vendor Data, mass balance		7. Emissions Method Code: 5
8. Calculation of Emissions: Potential emissions are based on the design cooling tower water flow, the design drift rate and the cycled water total dissolved solids. Design water flow = 111,130 gpm = 55,609,452 lb/hr Design drift rate = 0.0005% of design water flow Total dissolved solids = 2,380 ppm Hourly PM/PM10 emissions = 55,542,774 lb/hr x 0.0005/100 x 2,380 ppm/1,000,000 = 0.66 lb/hr The maximum annual PM/PM10 emissions = 0.66 lb/hr x 8,760 hr/yr x ton/2,000 lb = 2.89 tpy		
9. Pollutant Potential/Estimated Fugitive Emissions Comment:		

**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):	

EMISSIONS UNIT INFORMATION

Section [4] of [4]

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:	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:	

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:	

EMISSIONS UNIT INFORMATION

Section [4] of [4]

H. CONTINUOUS MONITOR INFORMATION

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:	

EMISSIONS UNIT INFORMATION

Section [4] of [4]

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) ☒ Attached, Document ID: <u>Attach. 2</u> ☐ 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) ☐ Attached, Document ID: <u>NA</u> ☐ 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: <u>See Section 3 of Application Support Document</u>
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 _____ ☒ 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) ☐ Attached, Document ID: _____ ☐ 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: _____ _____ ☒ 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: _____ ☒ Not Applicable

Section [4] of [4]

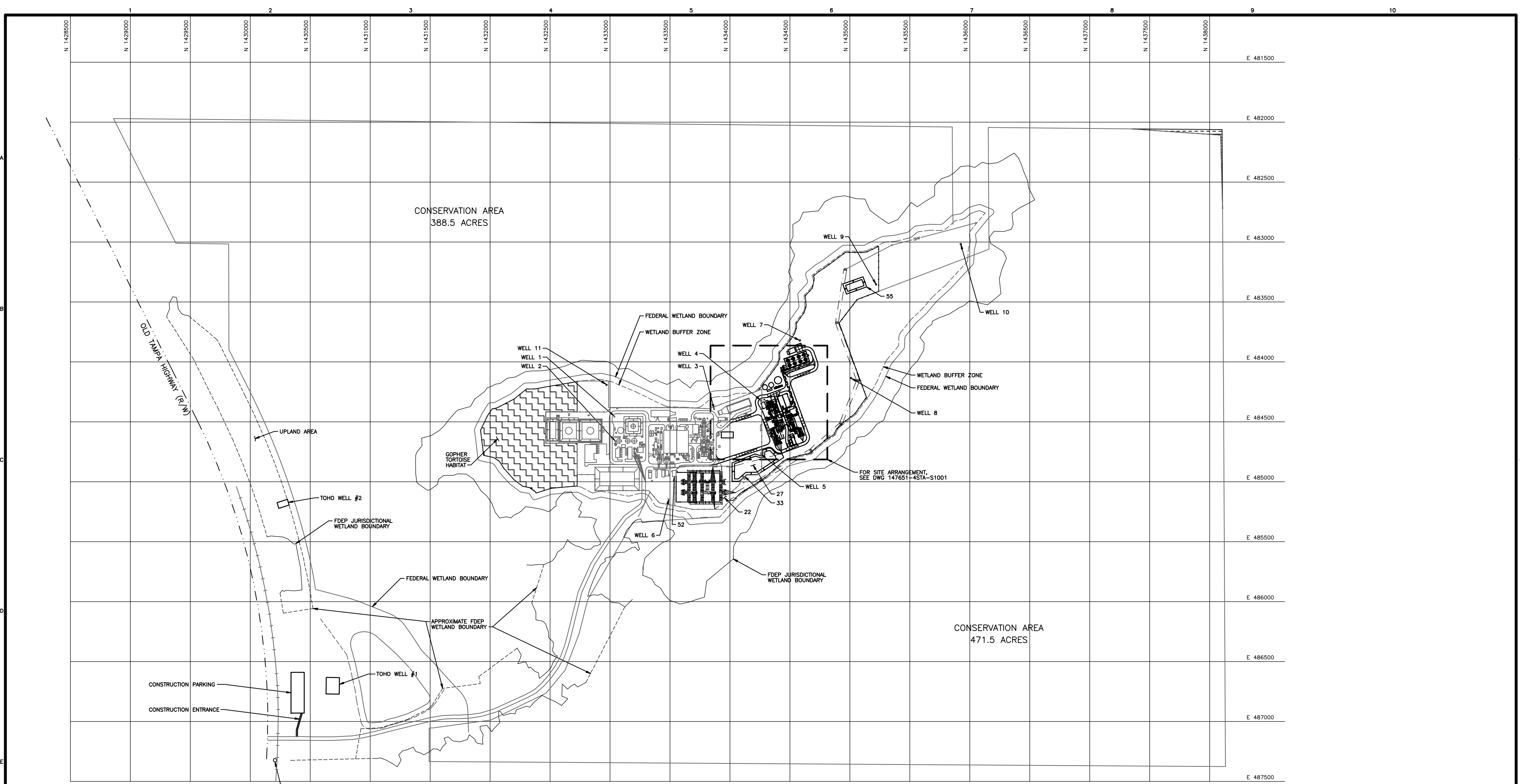
1. Control Technology Review and Analysis (Rules 62-212.400(6) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e))	☒ Attached, Document ID: <u>See Section 3 of the Application Support Document</u>
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(5)(h)6., F.A.C., and Rule 62-212.500(4)(f), F.A.C.)	☒ Attached, Document ID: <u>See Section 4 of Application Support Document</u>
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only)	☐ Attached, Document ID: _____ ☒ Not Applicable

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

[illegible]

Attachment 1
Facility Plot Plan

RM02025
03/26/08
ACAD 16.1s (LMS Tech)
03/26/08 DB:6:28



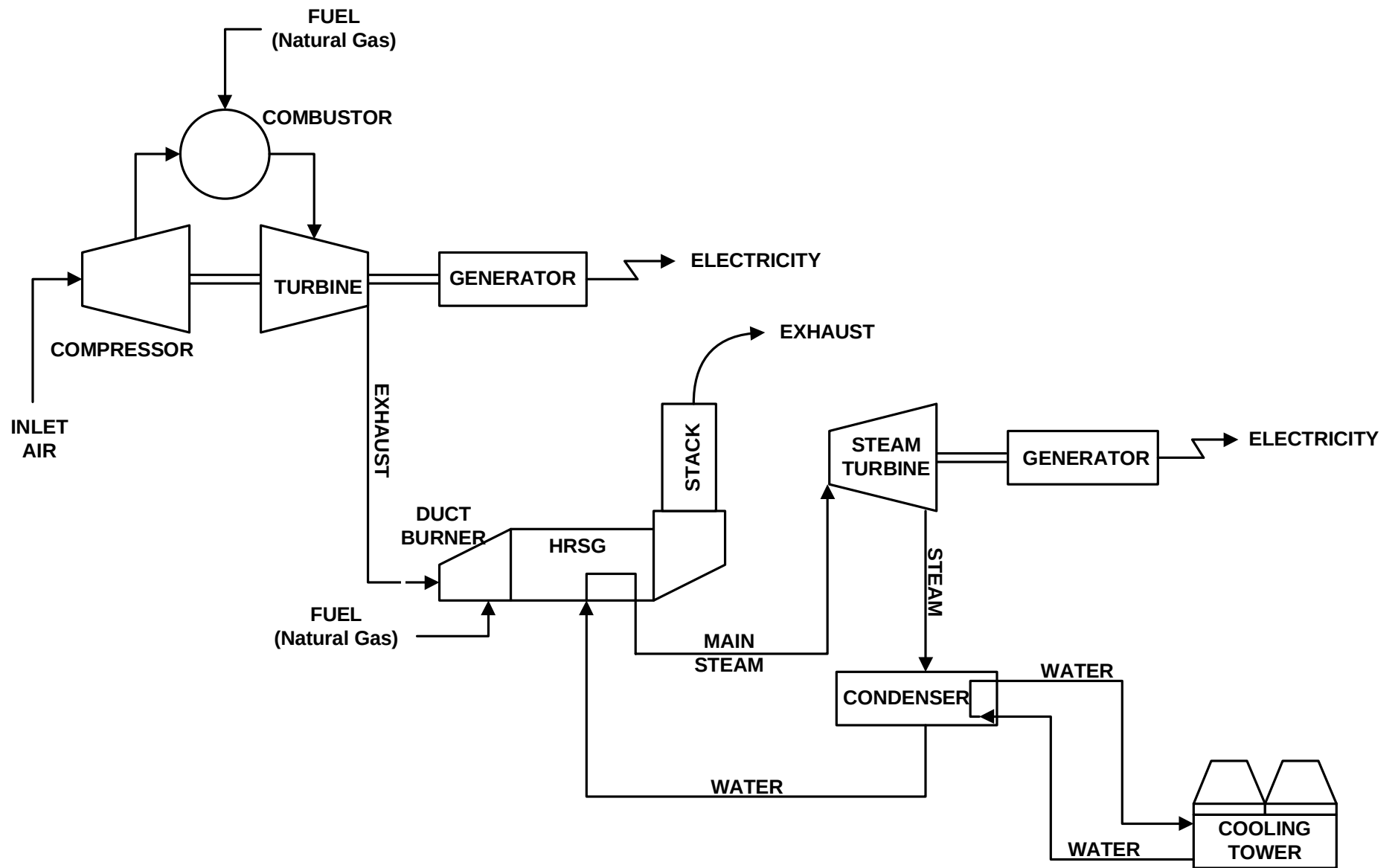
FACILITIES LEGEND	
ID	FACILITY
22	SUBSTATION
27	DETENTION POND
33	DETENTION POND DISCHARGE
52	SWITCHYARD CONTROL BUILDING (EXISTING)
55	PERC POND

LEGEND	
-----	WETLAND BUFFER ZONE
-----	FDEP JURISDICTIONAL WETLAND BOUNDARY
[Pattern]	GOPHER TORTOISE HABITAT
---	OVERHEAD TRANSMISSION LINE
---	FENCE LINE

NOTES	
FOR PERMITTING PURPOSE ONLY APPROVED FOR CONSTRUCTION	

FLORIDA MUNICIPAL POWER AGENCY CANE ISLAND POWER PARK UNIT 4		PROJECT 147651-4STA-S1000	DRAWING NUMBER 0
SITE PLAN		CODE AREA	REV FIG 2.1-3

Attachment 2
Process Flow Diagram



**Cane Island Unit 4
Combined 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 Combined Cycle Combustion Turbine

Only Initial Notification Applicable - Federal: 40 CFR Part 63 Subpart YYYY, *National Emission Standards for Stationary Combustion Turbines*. This standard is applicable to combustion turbine units at a facility that is a major source of HAPs. Natural gas fired turbines are exempt from the emission limit requirements but will have to file initial notification.

- Applicable - Federal: 40 CFR Part 60 Subpart KKKK – *Standards of Performance for Stationary Gas Turbines* – This rule applies to Unit 1, including the duct burner.
- Federal: 40 CFR Part 60 Subpart A – *General Provisions*.
- Federal: 40 CFR Part 72 – *Permits Regulation (Acid Rain)*
- Federal: 40 CFR Part 75 – *Continuous Emissions Monitoring*
- State: Rule 62-204.800(8)(d) – *General Provisions Adopted – 40 CFR 60 Subpart A – General Provisions adopted by reference, with exceptions*.
- State: Rule 62-212.400 – *Prevention of Significant Deterioration* applies to CO, NO_x, SO₂, PM, PM₁₀, and sulfuric acid mist. See the technical support document accompanying this application for a more detailed discussion of PSD applicability.
- State: Rule 62-212.300 – *General Preconstruction Review Requirements*. Applies to applicable pollutants not subject to PSD review.
- State: Rule 62-297.310 – *General Compliance Test Requirements*.

Rule Applicability Analysis for the Emergency Diesel Fire Pump and the Safe Shutdown 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 reciprocating internal combustion engines (RICE) rated greater than 500 BHP. The fire pump is rated at 290 BHP, thus 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:

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 Safe Shutdown Generator

The following rules are APPLICABLE to the Safe Shutdown Generator:

Federal: 40 CFR Part 63 Subpart ZZZZ, *National Emission Standards for Reciprocating Internal Combustion Engines*.

The safe shutdown generator is rated greater than the 500 BHP applicability threshold and thus is an affected unit under the RICE MACT. However, a new emergency stationary RICE located at a major source of HAPs is subject only to the initial notification requirements of 40 CFR 63.6645(d). Since the purpose of the safe shutdown generator will be for emergency situations when the normal source of power is not available to the facility, it will be considered as emergency stationary RICE and, therefore, subject only to the initial notification requirements of the RICE MACT.

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

The safe shutdown 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. The applicable standards associated with the safe shutdown generator will be dependent on the engine model year. Therefore, the exact emission standards applicable to the safe shutdown generator cannot be identified until the engine is purchased.

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

Attachment 5
Operation and Maintenance Plan

Attachment 5

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 6
Description of Stack Sampling Facilities

Attachment 6

Description of Stack Sampling Facilities

Unit 4 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 7
Acid Rain/CAIR/CAMR Program Forms

Attachment 7 Acid Rain/CAIR/CAMR Program Forms

In accordance with 62-213.420 F.A.C., since Unit 4 is not 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. FMPA understands that the forms will be incorporated into the Title V permit upon issuance of the revised, or renewal Title V permit, whichever comes first.

In accordance with 62-214.320, F.A.C., FMPA will submit a complete Acid Rain Part application governing Unit 4 operation to the Department at least 24 months before the date on which Unit 4 commences operation. Cane Island Unit 4 is expected to be operational May 1, 2011. The Acid Rain Part application will be submitted before May 1, 2009.

Appendix B
Combustion Turbine Performance Data and
Ancillary Equipment Specification Sheets

Combustion Turbine Performance Data

24-Jan-08 FMPA Cane Island Power Plant Black & Veatch Project 147651 1x1 Emissions Estimates, Revision 1												
Case Number CTG Model CTG Fuel Type CTG Load CTG Inlet Air Cooling CTG Steam/Water Injection Ambient Temperature, F HRSG Duct Firing Fuel Sulfur Content (grains/100 standard cubic feet)	1a PG7241 Natural Gas 100% Off No 19 Fired 2.00	2a PG7241 Natural Gas 100% Off No 19 Unfired 2.00	3a PG7241 Natural Gas 75% Off No 19 Unfired 2.00	4a PG7241 Natural Gas 50% Off No 19 Unfired 2.00	5a PG7241 Natural Gas 40% Off No 19 Unfired 2.00	6a PG7241 Natural Gas 100% Off No 59 Fired 2.00	7a PG7241 Natural Gas 100% Off No 59 Unfired 2.00	8a PG7241 Natural Gas 100% Evap. Cooler No 59 Fired 2.00	9a PG7241 Natural Gas 100% Evap. Cooler No 59 Unfired 2.00	10a PG7241 Natural Gas 75% Off No 59 Unfired 2.00	11a PG7241 Natural Gas 50% Off No 59 Unfired 2.00	12a PG7241 Natural Gas 40% Off No 59 Unfired 2.00
Ambient Conditions												
Ambient Temperature, F	19.0	19.0	19.0	19.0	19.0	59.0	59.0	59.0	59.0	59.0	59.0	59.0
Ambient Relative Humidity, %	58.0	58.0	58.0	58.0	58.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0
Atmospheric Pressure, psia	14.660	14.660	14.660	14.660	14.660	14.660	14.660	14.660	14.660	14.660	14.660	14.660
Combustion Turbine Performance												
CTG Performance Reference	GTP	GTP	GTP	GTP	GTP	GTP	GTP	GTP	GTP	GTP	GTP	GTP
CTG Inlet Air Conditioning Effectiveness, %	0	0	0	0	0	0	0	85	85	0	0	0
CTG Compressor Inlet Dry Bulb Temperature, F	19.0	19.0	19.0	19.0	19.0	59.0	59.0	52.6	52.6	59.0	59.0	59.0
CTG Compr. Inlet Relative Humidity, %	58.3	58.3	58.3	58.3	58.3	60.2	60.2	92.9	92.9	60.2	60.2	60.2
Inlet Loss, in. H2O	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Exhaust Loss, in. H2O	15.0	15.0	9.5	6.5	5.3	13.1	13.1	13.4	13.4	8.7	6.1	5.1
CTG Load Level (percent of Base Load)	100%	100%	75%	50%	40%	100%	100%	100%	100%	75%	50%	40%
Gross CTG Output, kW	190,700	190,700	143,000	95,400	76,300	173,500	173,500	176,800	176,800	130,200	86,800	69,400
Gross CTG Heat Rate, Btu/kWh (LHV)	9,337	9,337	9,775	11,720	12,960	9,522	9,522	9,486	9,486	10,070	12,090	13,360
Gross CTG Heat Rate, Btu/kWh (HHV)	10,357	10,357	10,843	13,001	14,376	10,563	10,563	10,523	10,523	11,171	13,411	14,820
CTG Heat Input, MBtu/h (LHV)	1,780.6	1,780.6	1,397.8	1,118.1	988.9	1,652.1	1,652.1	1,677.1	1,677.1	1,311.1	1,049.4	927.2
CTG Heat Input, MBtu/h (HHV)	1,975.2	1,975.2	1,550.6	1,240.3	1,096.9	1,832.6	1,832.6	1,860.4	1,860.4	1,454.4	1,164.1	1,028.5
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	3,867,000	3,867,000	3,042,000	2,489,000	2,248,000	3,590,000	3,590,000	3,634,000	3,634,000	2,895,000	2,395,000	2,190,000
CTG Exhaust Temperature, F	1,074	1,074	1,130	1,184	1,200	1,115	1,115	1,109	1,109	1,160	1,200	1,200
Combustion Turbine Fuel												
Total CTG Fuel Flow, lb/h	85,540	85,540	67,150	53,710	47,500	79,370	79,370	80,570	80,570	62,990	50,410	44,540
CTG Fuel Temperature, F	365	365	365	365	365	365	365	365	365	365	365	365
CTG Fuel LHV, Btu/lb	20,816	20,816	20,816	20,816	20,816	20,816	20,816	20,816	20,816	20,816	20,816	20,816
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	1.1093	1.1093	1.1093	1.1093	1.1093	1.1093	1.1093	1.1093	1.1093	1.1093	1.1093	1.1093
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%	73.76%	73.76%	73.76%	73.76%	73.76%	73.76%	73.76%	73.76%
H2	24.02%	24.02%	24.02%	24.02%	24.01%	24.01%	24.01%	24.01%	24.01%	24.01%	24.01%	24.01%
N2	0.59%	0.59%	0.59%	0.59%	0.61%	0.61%	0.61%	0.61%	0.61%	0.61%	0.61%	0.61%
O2	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%
S	0.00658%	0.00658%	0.00658%	0.00658%	0.00657%	0.00657%	0.00657%	0.00657%	0.00657%	0.00657%	0.00657%	0.00657%
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

24-Jan-08 FMPA Cane Island Power Plant Black & Veatch Project 147651 1x1 Emissions Estimates, Revision 1												
Case Number CTG Model CTG Fuel Type CTG Load CTG Inlet Air Cooling CTG Steam/Water Injection Ambient Temperature, F HRSG Duct Firing Fuel Sulfur Content (grains/100 standard cubic feet)	1a PG7241 Natural Gas 100% Off No 19 Fired 2.00	2a PG7241 Natural Gas 100% Off No 19 Unfired 2.00	3a PG7241 Natural Gas 75% Off No 19 Unfired 2.00	4a PG7241 Natural Gas 50% Off No 19 Unfired 2.00	5a PG7241 Natural Gas 40% Off No 19 Unfired 2.00	6a PG7241 Natural Gas 100% Off No 59 Fired 2.00	7a PG7241 Natural Gas 100% Off No 59 Unfired 2.00	8a PG7241 Natural Gas 100% Evap. Cooler No 59 Fired 2.00	9a PG7241 Natural Gas 100% Evap. Cooler No 59 Unfired 2.00	10a PG7241 Natural Gas 75% Off No 59 Unfired 2.00	11a PG7241 Natural Gas 50% Off No 59 Unfired 2.00	12a PG7241 Natural Gas 40% Off No 59 Unfired 2.00
Combustion Turbine Exhaust												
CTG Exhaust Analysis (Volume Basis - Wet)												
Ar	0.94%	0.94%	0.94%	0.94%	0.94%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	0.94%
CO2	3.87%	3.87%	3.86%	3.78%	3.70%	3.86%	3.86%	3.86%	3.86%	3.80%	3.67%	3.55%
H2O	7.70%	7.70%	7.69%	7.52%	7.37%	8.46%	8.46%	8.70%	8.70%	8.35%	8.11%	7.88%
N2	74.92%	74.92%	74.93%	75.00%	75.06%	74.32%	74.32%	74.14%	74.14%	74.37%	74.46%	74.55%
O2	12.56%	12.56%	12.58%	12.76%	12.93%	12.43%	12.43%	12.76%	12.36%	12.56%	12.82%	13.09%
SO2, (after SO2 oxidation)	0.00010%	0.00010%	0.00010%	0.00010%	0.00010%	0.00010%	0.00010%	0.00010%	0.00010%	0.00010%	0.00010%	0.00009%
SO3, (after SO2 oxidation)	0.00003%	0.00003%	0.00003%	0.00003%	0.00002%	0.00003%	0.00003%	0.00003%	0.00003%	0.00003%	0.00002%	0.00002%
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%
Molecular Wt, lb/mol	28.48	28.48	28.48	28.49	28.50	28.39	28.39	28.37	28.37	28.40	28.42	28.43
Specific Volume, ft^3/lb	38.01	38.01	39.92	41.56	42.07	39.32	39.32	39.18	39.18	40.86	42.11	42.20
Specific Volume, scf/lb	13.32	13.32	13.32	13.32	13.31	13.36	13.36	13.37	13.37	13.36	13.35	13.35
Exhaust Gas Flow, acfm	2,449,745	2,449,745	2,023,944	1,724,047	1,576,223	2,352,647	2,352,647	2,373,002	2,373,002	1,971,495	1,680,891	1,540,300
Exhaust Gas Flow, scfm	858,474	858,474	675,324	552,558	498,681	799,373	799,373	809,776	809,776	644,620	532,888	487,275
CTG NOx Emissions (Without Post Combustion Emissions Control)												
NOx, ppmvd (dry, 15% O2)	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00
NOx, ppmvd (dry)	11.10	11.10	11.10	10.80	10.60	11.10	11.10	11.20	11.20	11.00	10.60	10.20
NOx, ppmvw (wet)	10.20	10.20	10.20	10.00	9.80	10.20	10.20	10.20	10.20	10.00	9.70	9.40
NOx, lb/h as NO2	63.9	63.9	50.2	40.2	35.5	59.3	59.3	60.2	60.2	47.1	37.7	33.3
NOx, lb/MBtu (LHV)	0.0359	0.0359	0.0359	0.0359	0.0359	0.0359	0.0359	0.0359	0.0359	0.0359	0.0359	0.0359
NOx, lb/MBtu (HHV)	0.0324	0.0324	0.0324	0.0324	0.0324	0.0324	0.0324	0.0324	0.0324	0.0324	0.0324	0.0324
CTG CO Emissions (Without Post Combustion Emissions Control)												
CO, ppmvd (dry, 15% O2)	4.40	4.10	7.30	7.50	7.70	4.10	4.10	4.20	4.10	7.40	7.70	7.90
CO, ppmvd (dry)	5.40	5.10	9.00	9.00	9.00	5.10	5.10	5.20	5.10	9.00	9.00	9.00
CO, ppmvw (wet)	5.00	4.70	8.30	8.30	8.30	4.70	4.60	4.80	4.70	8.20	8.30	8.30
CO, lb/h	19.0	17.7	25.0	20.4	18.4	16.6	16.5	17.1	16.7	24.0	20.0	17.9
CO, lb/MBtu (LHV)	0.0107	0.0100	0.0179	0.0182	0.0186	0.0101	0.0100	0.0102	0.0100	0.0183	0.0191	0.0193
CO, lb/MBtu (HHV)	0.0096	0.0090	0.0161	0.0164	0.0168	0.0091	0.0090	0.0092	0.0090	0.0165	0.0172	0.0174
CTG SO2 Emissions (After SO2 Oxidation, Without Post Combustion Emissions Control)												
Assumed SO2 oxidation rate in CTG, 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%
SO2, ppmvd (dry, 15% O2)	0.9100	0.9100	0.9100	0.9100	0.9083	0.9083	0.9083	0.9083	0.9083	0.9083	0.9083	0.9083
SO2, ppmvd (dry)	1.1213	1.1213	1.1188	1.0922	1.0658	1.1243	1.1243	1.1294	1.1294	1.1053	1.0671	1.0290
SO2, ppmvw (wet)	1.0349	1.0349	1.0328	1.0100	0.9872	1.0291	1.0291	1.0311	1.0311	1.0130	0.9805	0.9479
SO2, lb/h	9.0027	9.0027	7.0672	5.6527	4.9885	8.3356	8.3356	8.4616	8.4616	6.6153	5.2941	4.6777
SO2, lb/MBtu (LHV)	0.0051	0.0051	0.0051	0.0051	0.0050	0.0050	0.0050	0.0050	0.0050	0.0050	0.0050	0.0050
SO2, lb/MBtu (HHV)	0.0046	0.0046	0.0046	0.0046	0.0045	0.0045	0.0045	0.0045	0.0045	0.0045	0.0045	0.0045

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Combustion Turbine Exhaust - continued												
CTG UHC Emissions (Without Post Combustion Emissions Control)												
UHC, ppmvd (dry, 15% O2)	6.2	6.2	6.2	6.3	6.4	6.2	6.2	6.2	6.2	6.3	6.5	6.7
UHC, ppmvd (dry)	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.7	7.7	7.6	7.6	7.6
UHC, ppmvw (wet)	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	15.2	15.2	12.0	10.0	8.9	14.2	14.2	14.4	14.4	11.4	9.5	8.7
UHC, lb/MBtu as CH4 (LHV)	0.0086	0.0086	0.0086	0.0089	0.0090	0.0086	0.0086	0.0086	0.0086	0.0087	0.0090	0.0093
UHC, lb/MBtu as CH4 (HHV)	0.0077	0.0077	0.0077	0.0081	0.0081	0.0077	0.0077	0.0077	0.0077	0.0079	0.0081	0.0084
CTG VOC Emissions (Without Post Combustion Emissions Control)												
VOC percentage of UHC	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
VOC, ppmvd (dry, 15% O2)	1.2	1.2	1.2	1.3	1.3	1.2	1.2	1.2	1.2	1.3	1.3	1.3
VOC, ppmvd (dry)	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	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	3.0	3.0	2.4	2.0	1.8	2.8	2.8	2.9	2.9	2.3	1.9	1.7
VOC, lb/MBtu as CH4 (LHV)	0.0017	0.0017	0.0017	0.0018	0.0018	0.0017	0.0017	0.0017	0.0017	0.0017	0.0018	0.0019
VOC, lb/MBtu as CH4 (HHV)	0.0015	0.0015	0.0015	0.0016	0.0016	0.0015	0.0015	0.0015	0.0015	0.0016	0.0016	0.0017
CTG PM10 Emissions (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	0.0051	0.0064	0.0080	0.0091	0.0054	0.0054	0.0054	0.0054	0.0069	0.0086	0.0097
PM10, lb/MBtu (HHV)	0.0046	0.0046	0.0058	0.0073	0.0082	0.0049	0.0049	0.0048	0.0048	0.0062	0.0077	0.0088
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	0.0101	0.0129	0.0161	0.0182	0.0109	0.0109	0.0107	0.0107	0.0137	0.0172	0.0194
PM10, lb/MBtu (HHV)	0.0091	0.0091	0.0116	0.0145	0.0164	0.0098	0.0098	0.0097	0.0097	0.0124	0.0155	0.0175

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HRSG Duct Burners												
Duct Burner Fuel												
Duct Burner Heat Input, MBtu/h (LHV)	534.8	0.0	0.0	0.0	0.0	534.8	0.0	534.8	0.0	0.0	0.0	0.0
Duct Burner Heat Input, MBtu/h (HHV)	593.2	0.0	0.0	0.0	0.0	593.2	0.0	593.2	0.0	0.0	0.0	0.0
Total Duct Burner Fuel Flow, lb/h	25,691	0	0	0	0	25,691	0	25,691	0	0	0	0
Duct Burner Fuel LHV, Btu/lb	20,816	20,816	20,816	20,816	20,816	20,816	20,816	20,816	20,816	20,816	20,816	20,816
Duct Burner 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
Duct Burner 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	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%
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	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
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
Duct Burner Emissions												
Duct Burner NOx, lb/MBtu (HHV)	0.080	0.080	0.080	0.080	0.080	0.080	0.080	0.080	0.080	0.080	0.080	0.080
Duct Burner CO, lb/MBtu (HHV)	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040
Duct Burner UHC (as CH4), lb/MBtu (HHV)	0.060	0.060	0.060	0.060	0.060	0.060	0.060	0.060	0.060	0.060	0.060	0.060
Duct Burner VOC (as CH4), lb/MBtu (HHV)	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004
Duct Burner PM10, lb/MBtu (HHV) (front half catch only)	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010
Duct Burner PM10, lb/MBtu (HHV) (front and back half catch)	0.024	0.024	0.024	0.024	0.024	0.024	0.024	0.024	0.024	0.024	0.024	0.024
Assumed SO2 oxidation rate in Duct Burner, vol%	10.0%	0.0%	0.0%	0.0%	0.0%	10.0%	0.0%	10.0%	0.0%	0.0%	0.0%	0.0%
Total SO2, lb/h from Duct Burner Fuel only (after SO2 oxidation)	3.042	0.000	0.000	0.000	0.000	3.042	0.000	3.042	0.000	0.000	0.000	0.000
Total SO3, lb/h from Duct Burner Fuel only (after SO2 oxidation)	0.422	0.000	0.000	0.000	0.000	0.422	0.000	0.422	0.000	0.000	0.000	0.000
DB NOx, lb/h	47.50	0.00	0.00	0.00	0.00	47.50	0.00	47.50	0.00	0.00	0.00	0.00
DB CO, lb/h	23.70	0.00	0.00	0.00	0.00	23.70	0.00	23.70	0.00	0.00	0.00	0.00
DB UHC (as CH4), lb/h	35.60	0.00	0.00	0.00	0.00	35.60	0.00	35.60	0.00	0.00	0.00	0.00
DB VOC (as CH4), lb/h	2.40	0.00	0.00	0.00	0.00	2.40	0.00	2.40	0.00	0.00	0.00	0.00
DB PM10, lb/h (front half catch only)	5.90	0.00	0.00	0.00	0.00	5.90	0.00	5.90	0.00	0.00	0.00	0.00
DB PM10, lb/h (front and back half catch)	14.20	0.00	0.00	0.00	0.00	14.20	0.00	14.20	0.00	0.00	0.00	0.00

24-Jan-08 FMPA Cane Island Power Plant Black & Veatch Project 147651 1x1 Emissions Estimates, Revision 1												
Case Number CTG Model CTG Fuel Type CTG Load CTG Inlet Air Cooling CTG Steam/Water Injection Ambient Temperature, F HRSG Duct Firing Fuel Sulfur Content (grains/100 standard cubic feet)	1a PG7241 Natural Gas 100% Off No 19 Fired 2.00	2a PG7241 Natural Gas 100% Off No 19 Unfired 2.00	3a PG7241 Natural Gas 75% Off No 19 Unfired 2.00	4a PG7241 Natural Gas 50% Off No 19 Unfired 2.00	5a PG7241 Natural Gas 40% Off No 19 Unfired 2.00	6a PG7241 Natural Gas 100% Off No 59 Fired 2.00	7a PG7241 Natural Gas 100% Off No 59 Unfired 2.00	8a PG7241 Natural Gas 100% Evap. Cooler No 59 Fired 2.00	9a PG7241 Natural Gas 100% Evap. Cooler No 59 Unfired 2.00	10a PG7241 Natural Gas 75% Off No 59 Unfired 2.00	11a PG7241 Natural Gas 50% Off No 59 Unfired 2.00	12a PG7241 Natural Gas 40% Off No 59 Unfired 2.00
Stack Emissions												
Stack Exhaust Analysis - Volume Basis - Wet												
Ar	0.93%	0.94%	0.94%	0.94%	0.94%	0.92%	0.93%	0.92%	0.93%	0.93%	0.93%	0.94%
CO2	4.98%	3.87%	3.86%	3.78%	3.70%	5.04%	3.86%	5.03%	3.86%	3.80%	3.67%	3.55%
H2O	9.85%	7.70%	7.69%	7.52%	7.37%	10.75%	8.46%	10.96%	8.70%	8.35%	8.11%	7.88%
N2	74.08%	74.92%	74.93%	75.00%	75.06%	73.43%	74.32%	73.26%	74.14%	74.37%	74.46%	74.55%
O2	10.16%	12.56%	12.58%	12.76%	12.93%	9.86%	12.43%	9.83%	12.36%	12.56%	12.82%	13.09%
SO2 (after SO2 oxidation)	0.000120%	0.000100%	0.000100%	0.000100%	0.000100%	0.000120%	0.000100%	0.000120%	0.000100%	0.000100%	0.000100%	0.000090%
SO3 (after SO2 oxidation)	0.000040%	0.000030%	0.000030%	0.000030%	0.000030%	0.000040%	0.000030%	0.000040%	0.000030%	0.000030%	0.000030%	0.000030%
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	166	178	166	157	154	166	180	167	180	169	161	158
Stack Diameter, ft (estimated)	18	18	18	18	18	18	18	18	18	18	18	18
Stack Flow, lb/h	3,892,687	3,866,996	3,041,997	2,488,998	2,247,998	3,615,687	3,589,996	3,659,687	3,633,996	2,894,997	2,394,998	2,189,998
Stack Flow, scfm	868,719	858,474	675,324	552,558	498,681	809,312	799,373	819,771	809,776	644,620	532,888	487,275
Stack Flow, acfm	1,047,783	1,056,336	815,256	657,096	590,100	976,839	986,053	990,556	999,956	781,168	637,469	580,350
Stack Exit Velocity, ft/s	69.0	69.0	53.0	43.0	39.0	64.0	65.0	65.0	65.0	51.0	42.0	38.0
Stack NOx Emissions without the Effects of Selective Catalytic Reduction (SCR)												
NOx, ppmvd (dry, 15% O2)	12.1	9.0	9.0	9.0	9.0	12.2	9.0	12.2	9.0	9.0	9.0	9.0
NOx, ppmvd (dry)	19.6	11.1	11.1	10.8	10.6	20.3	11.1	20.3	11.2	11.0	10.6	10.2
NOx, ppmvw (wet)	17.6	10.2	10.2	10.0	9.8	18.1	10.2	18.1	10.2	10.0	9.7	9.4
NOx, lb/h as NO2	111.4	63.9	50.2	40.2	35.5	106.8	59.3	107.7	60.2	47.1	37.7	33.3
NOx, lb/MBtu (LHV) as NO2 (incl. duct burner fuel)	0.0481	0.0359	0.0359	0.0359	0.0359	0.0488	0.0359	0.0487	0.0359	0.0359	0.0359	0.0359
NOx, lb/MBtu (HHV) as NO2 (incl. duct burner fuel)	0.0434	0.0324	0.0324	0.0324	0.0324	0.0440	0.0324	0.0439	0.0324	0.0324	0.0324	0.0324
Stack NOx Emissions with the Effects of Selective Catalytic Reduction (SCR)												
NOx, ppmvd (dry, 15% O2)	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
NOx, ppmvd (dry)	3.2	2.5	2.5	2.4	2.3	3.3	2.5	3.3	2.5	2.4	2.3	2.3
NOx, ppmvw (wet)	2.9	2.3	2.3	2.2	2.2	3.0	2.3	3.0	2.3	2.2	2.2	2.1
NOx, lb/h as NO2	18.5	14.2	11.2	8.9	7.9	17.5	13.2	17.6	13.4	10.5	8.4	7.4
NOx, lb/MBtu (LHV) as NO2 (incl. duct burner fuel)	0.0080	0.0080	0.0080	0.0080	0.0080	0.0080	0.0080	0.0080	0.0080	0.0080	0.0080	0.0080
NOx, lb/MBtu (HHV) as NO2 (incl. duct burner fuel)	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072
SCR NH3 slip, ppmvd (dry, 15% O2)	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
SCR NH3 slip, lb/h	17.1	13.2	10.3	8.3	7.3	16.2	12.2	16.3	12.4	9.7	7.7	6.8
Stack CO Emissions												
CO, ppmvd (dry, 15% O2)	7.6	4.1	7.3	7.5	7.7	7.6	4.1	7.6	4.1	7.4	7.7	7.9
CO, ppmvd (dry)	12.3	5.1	9.0	9.0	9.0	12.6	5.1	12.6	5.1	9.0	9.0	9.0
CO, ppmvw (wet)	11.1	4.7	8.3	8.3	8.3	11.3	4.6	11.2	4.7	8.2	8.3	8.3
CO, lb/h	42.8	17.7	25.0	20.4	18.4	40.4	16.5	40.8	16.7	24.0	20.0	17.9
CO, lb/MBtu (LHV) (incl. duct burner fuel)	0.0185	0.0100	0.0179	0.0182	0.0186	0.0185	0.0100	0.0185	0.0100	0.0183	0.0191	0.0193
CO, lb/MBtu (HHV) (incl. duct burner fuel)	0.0166	0.0090	0.0161	0.0164	0.0168	0.0166	0.0090	0.0166	0.0090	0.0165	0.0172	0.0174
Stack SO2 Emissions, after SO2 Oxidation												
Assumed SO2 oxidation rate in SCR, vol%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
SO2, ppmvd (dry, 15% O2)	0.84	0.88	0.88	0.88	0.88	0.84	0.88	0.84	0.88	0.88	0.88	0.88
SO2, ppmvd (dry)	1.36	1.09	1.09	1.06	1.03	1.40	1.09	1.40	1.10	1.07	1.04	1.00
SO2, ppmvw (wet)	1.23	1.00	1.00	0.98	0.96	1.25	1.00	1.24	1.00	0.98	0.95	0.92
SO2, lb/h	10.81	8.73	6.86	5.48	4.84	10.23	8.09	10.34	8.21	6.42	5.14	4.54
SO2, lb/MBtu (LHV) (incl. duct burner fuel)	0.0047	0.0049	0.0049	0.0049	0.0049	0.0047	0.0049	0.0047	0.0049	0.0049	0.0049	0.0049
SO2, lb/MBtu (HHV) (incl. duct burner fuel)	0.0042	0.0044	0.0044	0.0044	0.0044	0.0042	0.0044	0.0042	0.0044	0.0044	0.0044	0.0044

24-Jan-08 FMPA Cane Island Power Plant Black & Veatch Project 147651 1x1 Emissions Estimates, Revision 1												
Case Number CTG Model CTG Fuel Type CTG Load CTG Inlet Air Cooling CTG Steam/Water Injection Ambient Temperature, F HRSG Duct Firing Fuel Sulfur Content (grains/100 standard cubic feet)	1a PG7241 Natural Gas 100% Off No 19 Fired 2.00	2a PG7241 Natural Gas 100% Off No 19 Unfired 2.00	3a PG7241 Natural Gas 75% Off No 19 Unfired 2.00	4a PG7241 Natural Gas 50% Off No 19 Unfired 2.00	5a PG7241 Natural Gas 40% Off No 19 Unfired 2.00	6a PG7241 Natural Gas 100% Off No 59 Fired 2.00	7a PG7241 Natural Gas 100% Off No 59 Unfired 2.00	8a PG7241 Natural Gas 100% Evap. Cooler No 59 Fired 2.00	9a PG7241 Natural Gas 100% Evap. Cooler No 59 Unfired 2.00	10a PG7241 Natural Gas 75% Off No 59 Unfired 2.00	11a PG7241 Natural Gas 50% Off No 59 Unfired 2.00	12a PG7241 Natural Gas 40% Off No 59 Unfired 2.00
Stack Emissions - continued												
Stack UHC Emissions												
UHC, ppmvd (dry, 15% O2)	15.8	6.2	6.2	6.3	6.4	16.4	6.2	16.2	6.2	6.3	6.5	6.7
UHC, ppmvd	25.6	7.6	7.6	7.6	7.6	27.2	7.6	27.0	7.7	7.6	7.6	7.6
UHC, ppmvw	23.1	7.0	7.0	7.0	7.0	24.3	7.0	24.0	7.0	7.0	7.0	7.0
UHC, lb/h as CH4	50.8	15.2	12.0	10.0	8.9	49.8	14.2	50.0	14.4	11.4	9.5	8.7
UHC, lb/MBtu (LHV) (incl. duct burner fuel)	0.0220	0.0086	0.0086	0.0089	0.0090	0.0228	0.0086	0.0226	0.0086	0.0087	0.0090	0.0093
UHC, lb/MBtu (HHV) (incl. duct burner fuel)	0.0198	0.0077	0.0077	0.0081	0.0081	0.0205	0.0077	0.0204	0.0077	0.0079	0.0081	0.0084
Stack VOC Emissions												
VOC, ppmvd (dry, 15% O2)	1.7	1.2	1.2	1.3	1.3	1.7	1.2	1.7	1.2	1.3	1.3	1.3
VOC, ppmvd (dry)	2.7	1.5	1.5	1.5	1.5	2.8	1.5	2.8	1.5	1.5	1.5	1.5
VOC, ppmvw (wet)	2.5	1.4	1.4	1.4	1.4	2.5	1.4	2.5	1.4	1.4	1.4	1.4
VOC, lb/h as CH4	5.4	3.0	2.4	2.0	1.8	5.2	2.8	5.3	2.9	2.3	1.9	1.7
VOC, lb/MBtu (LHV) (incl. duct burner fuel)	0.0023	0.0017	0.0017	0.0018	0.0018	0.0024	0.0017	0.0024	0.0017	0.0017	0.0018	0.0019
VOC, lb/MBtu (HHV) (incl. duct burner fuel)	0.0021	0.0015	0.0015	0.0016	0.0016	0.0021	0.0015	0.0021	0.0015	0.0016	0.0016	0.0017
PM10 without the Effects of SO2 oxidation												
PM10 Emissions - Front Half Catch Only												
PM10, lb/h	14.9	9.0	9.0	9.0	9.0	14.9	9.0	14.9	9.0	9.0	9.0	9.0
PM10, lb/MBtu (LHV) (incl. duct burner fuel)	0.0064	0.0051	0.0064	0.0080	0.0091	0.0068	0.0054	0.0068	0.0054	0.0069	0.0086	0.0097
PM10, lb/MBtu (HHV) (incl. duct burner fuel)	0.0058	0.0046	0.0058	0.0073	0.0082	0.0062	0.0049	0.0061	0.0048	0.0062	0.0077	0.0088
PM10 Emissions - Front and Back Half Catch												
PM10, lb/h	32.2	18.0	18.0	18.0	18.0	32.2	18.0	32.2	18.0	18.0	18.0	18.0
PM10, lb/MBtu (LHV) (incl. duct burner fuel)	0.0139	0.0101	0.0129	0.0161	0.0182	0.0147	0.0109	0.0146	0.0107	0.0137	0.0172	0.0194
PM10, lb/MBtu (HHV) (incl. duct burner fuel)	0.0126	0.0091	0.0116	0.0145	0.0164	0.0133	0.0098	0.0131	0.0097	0.0124	0.0155	0.0175
PM10 with the Effects of SO2 Oxidation [includes (NH4)2-(SO4)]												
PM10 Emissions - Front Half Catch Only												
PM10, lb/h	14.9	9.0	9.0	9.0	9.0	14.9	9.0	14.9	9.0	9.0	9.0	9.0
PM10, lb/MBtu (LHV) (incl. duct burner fuel)	0.0064	0.0051	0.0064	0.0080	0.0091	0.0068	0.0054	0.0068	0.0054	0.0069	0.0086	0.0097
PM10, lb/MBtu (HHV) (incl. duct burner fuel)	0.0058	0.0046	0.0058	0.0073	0.0082	0.0062	0.0049	0.0061	0.0048	0.0062	0.0077	0.0088
PM10 Emissions - Front and Back Half Catch												
PM10, lb/h	40.1	23.2	22.1	21.3	20.9	39.6	22.8	39.7	22.9	21.8	21.1	20.7
PM10, lb/MBtu (LHV) (incl. duct burner fuel)	0.0173	0.0130	0.0158	0.0190	0.0211	0.0181	0.0138	0.0179	0.0136	0.0166	0.0201	0.0223
PM10, lb/MBtu (HHV) (incl. duct burner fuel)	0.0156	0.0117	0.0142	0.0171	0.0190	0.0163	0.0124	0.0162	0.0123	0.0150	0.0181	0.0201
Total Effects of SO2 Oxidation												
Total SO2 to SO3 conversion rate, %vol	26.1%	22.4%	22.4%	22.4%	22.4%	25.9%	22.4%	25.9%	22.4%	22.4%	22.4%	22.4%
Total Amount of SO2 converted to SO3, lb/h	3.82	2.52	1.98	1.58	1.40	3.57	2.33	3.62	2.37	1.85	1.48	1.31
Maximum Stack Ammonium Sulfate [(NH4)2-(SO4)] (assuming 100% conversion from SO3), lb/h	7.89	5.20	4.08	3.26	2.88	7.37	4.81	7.47	4.89	3.82	3.06	2.70
Maximum Stack H2SO4 (assuming 100% conversion from SO3 to H2SO4), lb/h	5.85	3.86	3.03	2.42	2.14	5.47	3.57	5.54	3.63	2.84	2.27	2.01

24-Jan-08 FMPPA Cane Island Power Plant Black & Veatch Project 147651 1x1 Emissions Estimates, Revision 1												
Case Number	1a	2a	3a	4a	5a	6a	7a	8a	9a	10a	11a	12a
CTG Model	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241
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%	100%	75%	50%	40%	100%	100%	100%	100%	75%	50%	40%
CTG Inlet Air Cooling	Off	Off	Off	Off	Off	Off	Off	Evap. Cooler	Evap. Cooler	Off	Off	Off
CTG Steam/Water Injection	No	No	No	No	No	No	No	No	No	No	No	No
Ambient Temperature, F	19	19	19	19	19	59	59	59	59	59	59	59
HRSO Duct Firing	Fired	Unfired	Unfired	Unfired	Unfired	Fired	Unfired	Fired	Unfired	Unfired	Unfired	Unfired
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
Post Combustion Emissions Control Equipment												
Selective Catalytic Reduction (SCR)												
NOx Removed in SCR, %wt	83.4%	77.8%	77.8%	77.8%	77.8%	83.7%	77.8%	83.6%	77.8%	77.8%	77.8%	77.8%
NOx removed in SCR, lb/h	92.9	49.7	39.0	31.2	27.6	89.3	46.1	90.0	46.8	36.6	29.3	25.9
Ammonia Slip, lb/h	17.1	13.2	10.3	8.3	7.3	16.2	12.2	16.3	12.4	9.7	7.7	6.8
Notes:												
1. The emissions estimates shown in the table above are per stack. 2. These estimates are based on expected CTG/Duct Burner emission guarantees. 3. The dry air composition used is 0.98% Ar, 78.03% N2 and 20.99% O2 4. ISO conditions are defined as 59 F, 14.696 psia and RH of 60%, Norm conditions are defined as 0 C, 1.103 bar 5. All ppm values are based on CH4 calibration gas. 6. The CTG performance is from General Electric dated 11/13/2007. 7. The H2O increase in the SCR catalyst is negligible and not included in the analysis. 8. The VOC/UHC ratios for NG were taken from the GE guarantee used in TCEC Unit 1. 9. Ammonium sulfates created downstream of the SCR are included in the back half particulates. The assumption that 100% SO3 is converted to ammonium sulfates results in "worst case" particulate emissions. 10. Where manufacturer data of lb/h of pollutant emissions were available, the greater of the manufacturer's estimate and B&V's estimate was used in the summary table, i.e. the B&V estimates were adjusted, where applicable. 11. The front half catch of CT particulate emissions is assumed to be half the amount of the front and back half catch. 12. As requested the SCR was designed to reduce the NOx stack emissions to 2 ppmvd@15%O2 when firing NG. 13. The emissions estimate is based on NG with a maximum sulfur content of 2.0 grains/100scf. 14. For the 100% load base and fired cases, a 3% margin on the heat rate was added while a 5% margin was added to the duct burner fuel flow on the fired cases.												

24-Jan-08 FMPA Cane Island Power Plant Black & Veatch Project 147651 1x1 Emissions Estimates, Revision 1														
Case Number CTG Model CTG Fuel Type CTG Load CTG Inlet Air Cooling CTG Steam/Water Injection Ambient Temperature, F HRSG Duct Firing Fuel Sulfur Content (grains/100 standard cubic feet)	13a PG7241 Natural Gas 100% Off No 73 Fired 2.00	14a PG7241 Natural Gas 100% Off No 73 Unfired 2.00	15a PG7241 Natural Gas 100% Evap. Cooler No 73 Fired 2.00	16a PG7241 Natural Gas 100% Evap. Cooler No 73 Unfired 2.00	17a PG7241 Natural Gas 75% Off No 73 Unfired 2.00	18a PG7241 Natural Gas 50% Off No 73 Unfired 2.00	19a PG7241 Natural Gas 40% Off No 73 Unfired 2.00	20a PG7241 Natural Gas 100% Off No 102 Fired 2.00	21a PG7241 Natural Gas 100% Off No 102 Unfired 2.00	22a PG7241 Natural Gas 100% Evap. Cooler No 102 Fired 2.00	23a PG7241 Natural Gas 100% Evap. Cooler No 102 Unfired 2.00	24a PG7241 Natural Gas 75% Off No 102 Unfired 2.00	25a PG7241 Natural Gas 50% Off No 102 Unfired 2.00	26a PG7241 Natural Gas 40% Off No 102 Unfired 2.00
Ambient Conditions														
Ambient Temperature, F	73.0	73.0	73.0	73.0	73.0	73.0	73.0	102.0	102.0	102.0	102.0	102.0	102.0	102.0
Ambient Relative Humidity, %	80.0	80.0	80.0	80.0	80.0	80.0	80.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0
Atmospheric Pressure, psia	14.660	14.660	14.660	14.660	14.660	14.660	14.660	14.660	14.660	14.660	14.660	14.660	14.660	14.660
Combustion Turbine Performance														
CTG Performance Reference	GTP	GTP	GTP	GTP	GTP	GTP	GTP	GTP	GTP	GTP	GTP	GTP	GTP	GTP
CTG Inlet Air Conditioning Effectiveness, %	0	0	85	85	0	0	0	0	0	85	85	0	0	0
CTG Compressor Inlet Dry Bulb Temperature, F	73.0	73.0	69.2	69.2	73.0	73.0	73.0	102.0	102.0	80.9	80.9	102.0	102.0	102.0
CTG Compr. Inlet Relative Humidity, %	80.1	80.1	96.7	96.7	80.1	80.1	80.1	33.1	33.1	84.8	84.8	33.1	33.1	33.1
Inlet Loss, in. H2O	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Exhaust Loss, in. H2O	12.4	12.4	12.5	12.5	8.4	5.9	4.9	10.8	10.8	11.9	11.9	7.6	5.5	4.6
CTG Load Level (percent of Base Load)	100%	100%	100%	100%	75%	50%	40%	100%	100%	100%	100%	75%	50%	40%
Gross CTG Output, kW	166,300	166,300	168,300	168,300	124,700	83,100	66,500	147,300	147,300	161,600	161,600	110,500	73,700	58,900
Gross CTG Heat Rate, Btu/kWh (LHV)	9,641	9,641	9,615	9,615	10,250	12,270	13,570	9,981	9,981	9,728	9,728	10,720	12,820	14,250
Gross CTG Heat Rate, Btu/kWh (HHV)	10,695	10,695	10,666	10,666	11,370	13,611	15,053	11,072	11,072	10,791	10,791	11,892	14,221	15,807
CTG Heat Input, MBtu/h (LHV)	1,603.3	1,603.3	1,618.2	1,618.2	1,278.2	1,019.6	902.4	1,470.2	1,470.2	1,572.0	1,572.0	1,184.6	944.8	839.3
CTG Heat Input, MBtu/h (HHV)	1,778.5	1,778.5	1,795.1	1,795.1	1,417.9	1,131.1	1,001.0	1,630.9	1,630.9	1,743.9	1,743.9	1,314.0	1,048.1	931.1
CTG Water/Steam Injection Flow, lb/h	0	0	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	0.0	0.0
CTG Exhaust Flow, lb/h	3,470,000	3,470,000	3,497,000	3,497,000	2,834,000	2,356,000	2,154,000	3,221,000	3,221,000	3,393,000	3,393,000	2,679,000	2,272,000	2,088,000
CTG Exhaust Temperature, F	1,131	1,131	1,127	1,127	1,171	1,200	1,200	1,163	1,163	1,141	1,141	1,198	1,200	1,200
Combustion Turbine Fuel														
Total CTG Fuel Flow, lb/h	77,020	77,020	77,740	77,740	61,400	48,980	43,350	70,630	70,630	75,520	75,520	56,910	45,390	40,320
CTG Fuel Temperature, F	365	365	365	365	365	365	365	365	365	365	365	365	365	365
CTG Fuel LHV, Btu/lb	20,816	20,816	20,816	20,816	20,816	20,816	20,816	20,816	20,816	20,816	20,816	20,816	20,816	20,816
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	23,091	23,091
HHV/LHV Ratio	1.1093	1.1093	1.1093	1.1093	1.1093	1.1093	1.1093	1.1093	1.1093	1.1093	1.1093	1.1093	1.1093	1.1093
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%	0.00%	0.00%
C	73.78%	73.78%	73.78%	73.78%	73.78%	73.78%	73.78%	73.76%	73.76%	73.78%	73.78%	73.78%	73.78%	73.76%
H2	24.02%	24.02%	24.02%	24.02%	24.02%	24.02%	24.02%	24.01%	24.01%	24.01%	24.02%	24.02%	24.02%	24.01%
N2	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%	0.61%	0.61%	0.61%	0.59%	0.59%	0.59%	0.59%	0.61%
O2	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%
S	0.00658%	0.00658%	0.00658%	0.00658%	0.00658%	0.00658%	0.00657%	0.00657%	0.00657%	0.00658%	0.00658%	0.00658%	0.00658%	0.00657%
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%	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	2.00	2.00

24-Jan-08 FMPA Cane Island Power Plant Black & Veatch Project 147651 1x1 Emissions Estimates, Revision 1															
Case Number CTG Model CTG Fuel Type CTG Load CTG Inlet Air Cooling CTG Steam/Water Injection Ambient Temperature, F HRSG Duct Firing Fuel Sulfur Content (grains/100 standard cubic feet)	13a PG7241 Natural Gas 100% Off No 73 Fired 2.00	14a PG7241 Natural Gas 100% Off No 73 Unfired 2.00	15a PG7241 Natural Gas 100% Evap. Cooler No 73 Fired 2.00	16a PG7241 Natural Gas 100% Evap. Cooler No 73 Unfired 2.00	17a PG7241 Natural Gas 75% Off No 73 Unfired 2.00	18a PG7241 Natural Gas 50% Off No 73 Unfired 2.00	19a PG7241 Natural Gas 40% Off No 73 Unfired 2.00	20a PG7241 Natural Gas 100% Off No 102 Fired 2.00	21a PG7241 Natural Gas 100% Off No 102 Unfired 2.00	22a PG7241 Natural Gas 100% Evap. Cooler No 102 Fired 2.00	23a PG7241 Natural Gas 100% Evap. Cooler No 102 Unfired 2.00	24a PG7241 Natural Gas 75% Off No 102 Unfired 2.00	25a PG7241 Natural Gas 50% Off No 102 Unfired 2.00	26a PG7241 Natural Gas 40% Off No 102 Unfired 2.00	
Combustion Turbine Exhaust															
CTG Exhaust Analysis (Volume Basis - Wet)															
Ar	0.92%	0.92%	0.92%	0.92%	0.92%	0.92%	0.93%	0.92%	0.92%	0.91%	0.91%	0.92%	0.92%	0.93%	
CO2	3.85%	3.85%	3.86%	3.86%	3.76%	3.61%	3.50%	3.81%	3.81%	3.85%	3.85%	3.69%	3.47%	3.36%	
H2O	9.61%	9.61%	9.75%	9.75%	9.44%	9.15%	8.93%	9.60%	9.60%	10.41%	10.41%	9.38%	8.96%	8.74%	
N2	73.43%	73.43%	73.32%	73.32%	73.49%	73.60%	73.69%	73.40%	73.40%	72.80%	72.80%	73.48%	73.65%	73.73%	
O2	12.19%	12.19%	12.15%	12.15%	12.38%	12.71%	12.96%	12.27%	12.27%	12.02%	12.02%	12.53%	12.99%	13.24%	
SO2, (after SO2 oxidation)	0.00010%	0.00010%	0.00010%	0.00010%	0.00010%	0.00010%	0.00009%	0.00010%	0.00010%	0.00010%	0.00010%	0.00010%	0.00009%	0.00009%	
SO3, (after SO2 oxidation)	0.00003%	0.00003%	0.00003%	0.00003%	0.00003%	0.00002%	0.00002%	0.00003%	0.00003%	0.00003%	0.00003%	0.00002%	0.00002%	0.00002%	
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%	100.0%	100.0%	
Molecular Wt, lb/mol	28.27	28.27	28.25	28.25	28.28	28.30	28.31	28.26	28.26	28.18	28.18	28.28	28.30	28.32	
Specific Volume, ft³/lb	39.96	39.96	39.87	39.87	41.35	42.31	42.39	40.93	40.93	40.39	40.39	42.11	42.34	42.41	
Specific Volume, scf/lb	13.42	13.42	13.43	13.43	13.42	13.41	13.40	13.42	13.42	13.46	13.46	13.42	13.40	13.40	
Exhaust Gas Flow, acfm	2,311,020	2,311,020	2,323,757	2,323,757	1,953,098	1,661,373	1,521,801	2,197,259	2,197,259	2,284,055	2,284,055	1,880,212	1,603,275	1,475,868	
Exhaust Gas Flow, scfm	776,123	776,123	782,745	782,745	633,871	526,566	481,060	720,430	720,430	761,163	761,163	599,203	507,413	466,320	
CTG NOx Emissions (Without Post Combustion Emissions Control)															
NOx, ppmvd (dry, 15% O2)	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	
NOx, ppmvd (dry)	11.30	11.30	11.30	11.30	11.00	10.50	10.20	11.10	11.10	11.40	11.40	10.80	10.10	9.70	
NOx, ppmwv (wet)	10.20	10.20	10.20	10.20	10.00	9.60	9.30	10.10	10.10	10.20	10.20	9.80	9.20	8.90	
NOx, lb/h as NO2	57.6	57.6	58.1	58.1	46.0	36.6	32.4	52.8	52.8	56.5	56.5	42.5	33.9	30.1	
NOx, lb/MBtu (LHV)	0.0359	0.0359	0.0359	0.0359	0.0360	0.0359	0.0359	0.0359	0.0359	0.0359	0.0359	0.0359	0.0359	0.0359	
NOx, lb/MBtu (HHV)	0.0324	0.0324	0.0324	0.0324	0.0324	0.0324	0.0324	0.0324	0.0324	0.0324	0.0324	0.0324	0.0324	0.0324	
CTG CO Emissions (Without Post Combustion Emissions Control)															
CO, ppmvd (dry, 15% O2)	4.00	4.10	4.10	4.10	7.40	7.70	8.00	3.70	4.10	4.00	4.10	7.50	8.00	8.30	
CO, ppmvd (dry)	5.10	5.10	5.10	5.20	9.00	9.00	9.00	4.60	5.10	5.00	5.20	9.00	9.00	9.00	
CO, ppmwv (wet)	4.60	4.60	4.60	4.60	8.20	8.20	8.20	4.20	4.60	4.50	4.60	8.20	8.20	8.20	
CO, lb/h	15.7	16.0	16.0	16.1	23.0	19.1	17.5	13.3	14.6	15.2	15.7	22.0	18.4	17.0	
CO, lb/MBtu (LHV)	0.0098	0.0100	0.0099	0.0100	0.0180	0.0187	0.0194	0.0090	0.0100	0.0096	0.0100	0.0186	0.0195	0.0202	
CO, lb/MBtu (HHV)	0.0089	0.0090	0.0089	0.0090	0.0162	0.0169	0.0175	0.0081	0.0090	0.0087	0.0090	0.0167	0.0176	0.0182	
CTG SO2 Emissions (After SO2 Oxidation, Without Post Combustion Emissions Control)															
Assumed SO2 oxidation rate in CTG, 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%	20.0%	20.0%	
SO2, ppmvd (dry, 15% O2)	0.9100	0.9100	0.9100	0.9100	0.9100	0.9100	0.9083	0.9083	0.9083	0.9100	0.9100	0.9100	0.9100	0.9083	
SO2, ppmvd (dry)	1.1404	1.1404	1.1433	1.1433	1.1114	1.0638	1.0256	1.1240	1.1240	1.1502	1.1502	1.0890	1.0204	0.9823	
SO2, ppmwv (wet)	1.0308	1.0308	1.0319	1.0319	1.0065	0.9665	0.9340	1.0161	1.0161	1.0304	1.0304	0.9869	0.9290	0.8965	
SO2, lb/h	8.1060	8.1060	8.1818	8.1818	6.4621	5.1549	4.5527	7.4177	7.4177	7.9481	7.9481	5.9895	4.7771	4.2345	
SO2, lb/MBtu (LHV)	0.0051	0.0051	0.0051	0.0051	0.0051	0.0051	0.0050	0.0050	0.0050	0.0051	0.0051	0.0051	0.0051	0.0050	
SO2, lb/MBtu (HHV)	0.0046	0.0046	0.0046	0.0046	0.0046	0.0046	0.0045	0.0045	0.0045	0.0046	0.0046	0.0046	0.0046	0.0045	

24-Jan-08 FMPA Cane Island Power Plant Black & Veatch Project 147651 1x1 Emissions Estimates, Revision 1														
Case Number CTG Model CTG Fuel Type CTG Load CTG Inlet Air Cooling CTG Steam/Water Injection Ambient Temperature, F HRSG Duct Firing Fuel Sulfur Content (grains/100 standard cubic feet)	13a PG7241 Natural Gas 100% Off No 73 Fired 2.00	14a PG7241 Natural Gas 100% Off No 73 Unfired 2.00	15a PG7241 Natural Gas 100% Evap. Cooler No 73 Fired 2.00	16a PG7241 Natural Gas 100% Evap. Cooler No 73 Unfired 2.00	17a PG7241 Natural Gas 75% Off No 73 Unfired 2.00	18a PG7241 Natural Gas 50% Off No 73 Unfired 2.00	19a PG7241 Natural Gas 40% Off No 73 Unfired 2.00	20a PG7241 Natural Gas 100% Off No 102 Fired 2.00	21a PG7241 Natural Gas 100% Off No 102 Unfired 2.00	22a PG7241 Natural Gas 100% Evap. Cooler No 102 Fired 2.00	23a PG7241 Natural Gas 100% Evap. Cooler No 102 Unfired 2.00	24a PG7241 Natural Gas 75% Off No 102 Unfired 2.00	25a PG7241 Natural Gas 50% Off No 102 Unfired 2.00	26a PG7241 Natural Gas 40% Off No 102 Unfired 2.00
Combustion Turbine Exhaust - continued														
CTG UHC Emissions (Without Post Combustion Emissions Control)														
UHC, ppmvd (dry, 15% O2)	6.2	6.2	6.2	6.2	6.3	6.6	6.8	6.3	6.3	6.2	6.2	6.5	6.9	7.1
UHC, ppmvd (dry)	7.7	7.7	7.8	7.8	7.7	7.7	7.7	7.7	7.7	7.8	7.8	7.7	7.7	7.7
UHC, ppmvw (wet)	7.0	7.0	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	13.8	13.8	13.9	13.9	11.3	9.4	8.5	12.8	12.8	13.5	13.5	11.0	9.0	8.3
UHC, lb/MBtu as CH4 (LHV)	0.0086	0.0086	0.0086	0.0086	0.0088	0.0092	0.0095	0.0087	0.0087	0.0086	0.0086	0.0093	0.0095	0.0099
UHC, lb/MBtu as CH4 (HHV)	0.0078	0.0078	0.0077	0.0077	0.0079	0.0083	0.0085	0.0078	0.0078	0.0078	0.0078	0.0084	0.0086	0.0089
CTG VOC Emissions (Without Post Combustion Emissions Control)														
VOC percentage of UHC	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
VOC, ppmvd (dry, 15% O2)	1.2	1.2	1.2	1.2	1.3	1.3	1.4	1.3	1.3	1.2	1.2	1.3	1.4	1.4
VOC, ppmvd (dry)	1.5	1.5	1.6	1.6	1.5	1.5	1.5	1.5	1.5	1.6	1.6	1.5	1.5	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	1.4	1.4
VOC, lb/h as CH4	2.8	2.8	2.8	2.8	2.3	1.9	1.7	2.6	2.6	2.7	2.7	2.2	1.8	1.7
VOC, lb/MBtu as CH4 (LHV)	0.0017	0.0017	0.0017	0.0017	0.0018	0.0018	0.0019	0.0017	0.0017	0.0017	0.0017	0.0019	0.0019	0.0020
VOC, lb/MBtu as CH4 (HHV)	0.0016	0.0016	0.0015	0.0015	0.0016	0.0017	0.0017	0.0016	0.0016	0.0016	0.0016	0.0017	0.0017	0.0018
CTG PM10 Emissions (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	9.0	9.0
PM10, lb/MBtu (LHV)	0.0056	0.0056	0.0056	0.0056	0.0070	0.0088	0.0100	0.0061	0.0061	0.0057	0.0057	0.0076	0.0095	0.0107
PM10, lb/MBtu (HHV)	0.0051	0.0051	0.0050	0.0050	0.0063	0.0080	0.0090	0.0055	0.0055	0.0052	0.0052	0.0068	0.0086	0.0097
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	18.0	18.0
PM10, lb/MBtu (LHV)	0.0112	0.0112	0.0111	0.0111	0.0141	0.0177	0.0199	0.0122	0.0122	0.0115	0.0115	0.0152	0.0191	0.0214
PM10, lb/MBtu (HHV)	0.0101	0.0101	0.0100	0.0100	0.0127	0.0159	0.0180	0.0110	0.0110	0.0103	0.0103	0.0137	0.0172	0.0193

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Case Number CTG Model CTG Fuel Type CTG Load CTG Inlet Air Cooling CTG Steam/Water Injection Ambient Temperature, F HRSG Duct Firing Fuel Sulfur Content (grains/100 standard cubic feet)	13a PG7241 Natural Gas 100% Off No 73 Fired 2.00	14a PG7241 Natural Gas 100% Off No 73 Unfired 2.00	15a PG7241 Natural Gas 100% Evap. Cooler No 73 Fired 2.00	16a PG7241 Natural Gas 100% Evap. Cooler No 73 Unfired 2.00	17a PG7241 Natural Gas 75% Off No 73 Unfired 2.00	18a PG7241 Natural Gas 50% Off No 73 Unfired 2.00	19a PG7241 Natural Gas 40% Off No 73 Unfired 2.00	20a PG7241 Natural Gas 100% Off No 102 Fired 2.00	21a PG7241 Natural Gas 100% Off No 102 Unfired 2.00	22a PG7241 Natural Gas 100% Evap. Cooler No 102 Fired 2.00	23a PG7241 Natural Gas 100% Evap. Cooler No 102 Unfired 2.00	24a PG7241 Natural Gas 75% Off No 102 Unfired 2.00	25a PG7241 Natural Gas 50% Off No 102 Unfired 2.00	26a PG7241 Natural Gas 40% Off No 102 Unfired 2.00
HRSG Duct Burners														
Duct Burner Fuel														
Duct Burner Heat Input, MBtu/h (LHV)	534.8	0.0	534.8	0.0	0.0	0.0	0.0	534.8	0.0	534.8	0.0	0.0	0.0	0.0
Duct Burner Heat Input, MBtu/h (HHV)	593.2	0.0	593.2	0.0	0.0	0.0	0.0	593.2	0.0	593.2	0.0	0.0	0.0	0.0
Total Duct Burner Fuel Flow, lb/h	25,691	0	25,691	0	0	0	0	25,691	0	25,691	0	0	0	0
Duct Burner Fuel LHV, Btu/lb	20,816	20,816	20,816	20,816	20,816	20,816	20,816	20,816	20,816	20,816	20,816	20,816	20,816	20,816
Duct Burner 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	23,091	23,091
Duct Burner 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%	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%	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%	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%	0.59%	0.59%
O2	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%
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%	0.00658%	0.00658%
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%	100.0%	100.0%
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	2.00	2.00
Duct Burner Emissions														
Duct Burner NOx, lb/MBtu (HHV)	0.080	0.080	0.080	0.080	0.080	0.080	0.080	0.080	0.080	0.080	0.080	0.080	0.080	0.080
Duct Burner CO, lb/MBtu (HHV)	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040	0.040
Duct Burner UHC (as CH4), lb/MBtu (HHV)	0.060	0.060	0.060	0.060	0.060	0.060	0.060	0.060	0.060	0.060	0.060	0.060	0.060	0.060
Duct Burner VOC (as CH4), lb/MBtu (HHV)	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004
Duct Burner PM10, lb/MBtu (HHV) (front half catch only)	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010
Duct Burner PM10, lb/MBtu (HHV) (front and back half catch)	0.024	0.024	0.024	0.024	0.024	0.024	0.024	0.024	0.024	0.024	0.024	0.024	0.024	0.024
Assumed SO2 oxidation rate in Duct Burner, vol%	10.0%	0.0%	10.0%	0.0%	0.0%	0.0%	0.0%	10.0%	0.0%	10.0%	0.0%	0.0%	0.0%	0.0%
Total SO2, lb/h from Duct Burner Fuel only (after SO2 oxidation)	3.042	0.000	3.042	0.000	0.000	0.000	0.000	3.042	0.000	3.042	0.000	0.000	0.000	0.000
Total SO3, lb/h from Duct Burner Fuel only (after SO2 oxidation)	0.422	0.000	0.422	0.000	0.000	0.000	0.000	0.422	0.000	0.422	0.000	0.000	0.000	0.000
DB NOx, lb/h	47.50	0.00	47.50	0.00	0.00	0.00	0.00	47.50	0.00	47.50	0.00	0.00	0.00	0.00
DB CO, lb/h	23.70	0.00	23.70	0.00	0.00	0.00	0.00	23.70	0.00	23.70	0.00	0.00	0.00	0.00
DB UHC (as CH4), lb/h	35.60	0.00	35.60	0.00	0.00	0.00	0.00	35.60	0.00	35.60	0.00	0.00	0.00	0.00
DB VOC (as CH4), lb/h	2.40	0.00	2.40	0.00	0.00	0.00	0.00	2.40	0.00	2.40	0.00	0.00	0.00	0.00
DB PM10, lb/h (front half catch only)	5.90	0.00	5.90	0.00	0.00	0.00	0.00	5.90	0.00	5.90	0.00	0.00	0.00	0.00
DB PM10, lb/h (front and back half catch)	14.20	0.00	14.20	0.00	0.00	0.00	0.00	14.20	0.00	14.20	0.00	0.00	0.00	0.00

24-Jan-08 FMPA Cane Island Power Plant Black & Veatch Project 147651 1x1 Emissions Estimates, Revision 1															
Case Number CTG Model CTG Fuel Type CTG Load CTG Inlet Air Cooling CTG Steam/Water Injection Ambient Temperature, F HRSG Duct Firing Fuel Sulfur Content (grains/100 standard cubic feet)	13a PG7241 Natural Gas 100% Off No 73 Fired 2.00	14a PG7241 Natural Gas 100% Off No 73 Unfired 2.00	15a PG7241 Natural Gas 100% Evap. Cooler No 73 Fired 2.00	16a PG7241 Natural Gas 100% Evap. Cooler No 73 Unfired 2.00	17a PG7241 Natural Gas 75% Off No 73 Unfired 2.00	18a PG7241 Natural Gas 50% Off No 73 Unfired 2.00	19a PG7241 Natural Gas 40% Off No 73 Unfired 2.00	20a PG7241 Natural Gas 100% Off No 102 Fired 2.00	21a PG7241 Natural Gas 100% Off No 102 Unfired 2.00	22a PG7241 Natural Gas 100% Evap. Cooler No 102 Fired 2.00	23a PG7241 Natural Gas 100% Evap. Cooler No 102 Unfired 2.00	24a PG7241 Natural Gas 75% Off No 102 Unfired 2.00	25a PG7241 Natural Gas 50% Off No 102 Unfired 2.00	26a PG7241 Natural Gas 40% Off No 102 Unfired 2.00	
Stack Emissions															
Stack Exhaust Analysis - Volume Basis - Wet															
Ar	0.91%	0.92%	0.91%	0.92%	0.92%	0.92%	0.93%	0.91%	0.92%	0.90%	0.91%	0.92%	0.92%	0.92%	0.93%
CO2	5.08%	3.85%	5.07%	3.86%	3.76%	3.61%	3.50%	5.12%	3.81%	5.10%	3.85%	3.69%	3.47%	3.36%	
H2O	11.95%	9.61%	12.07%	9.75%	9.44%	9.15%	8.93%	12.12%	9.60%	12.79%	10.41%	9.38%	8.96%	8.74%	
N2	72.52%	73.43%	72.42%	73.32%	73.49%	73.60%	73.69%	72.42%	73.40%	71.88%	72.80%	73.48%	73.65%	73.73%	
O2	9.55%	12.19%	9.53%	12.15%	12.38%	12.71%	12.96%	9.43%	12.27%	9.33%	12.02%	12.53%	12.99%	13.24%	
SO2 (after SO2 oxidation)	0.000130%	0.000100%	0.000130%	0.000100%	0.000100%	0.000090%	0.000090%	0.000130%	0.000100%	0.000130%	0.000100%	0.000100%	0.000090%	0.000090%	
SO3 (after SO2 oxidation)	0.000040%	0.000030%	0.000040%	0.000030%	0.000030%	0.000030%	0.000030%	0.000040%	0.000030%	0.000040%	0.000030%	0.000030%	0.000030%	0.000030%	
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%	100.0%	100.0%	
Stack Exit Temperature, F	167	182	167	182	172	164	162	165	180	168	183	171	165	163	
Stack Diameter, ft (estimated)	18	18	18	18	18	18	18	18	18	18	18	18	18	18	
Stack Flow, lb/h	3,495,687	3,469,996	3,522,687	3,496,996	2,833,997	2,355,998	2,153,998	3,246,688	3,220,997	3,418,687	3,392,997	2,678,997	2,271,998	2,087,998	
Stack Flow, scfm	785,948	776,123	792,606	782,745	633,871	526,566	481,060	730,506	720,430	770,915	761,163	599,203	507,413	466,320	
Stack Flow, acfm	950,245	960,612	958,759	969,252	771,793	633,371	576,554	879,853	888,996	933,303	944,385	728,688	611,925	559,932	
Stack Exit Velocity, ft/s	62.0	63.0	63.0	63.0	51.0	41.0	38.0	58.0	58.0	61.0	62.0	48.0	40.0	37.0	
Stack NOx Emissions without the Effects of Selective Catalytic Reduction (SCR)															
NOx, ppmvd (dry, 15% O2)	12.3	9.0	12.3	9.0	9.0	9.0	9.0	12.5	9.0	12.4	9.0	9.0	9.0	9.0	
NOx, ppmvd (dry)	20.9	11.3	20.8	11.3	11.0	10.5	10.2	21.5	11.1	21.2	11.4	10.8	10.1	9.7	
NOx, ppmvw (wet)	18.4	10.2	18.3	10.2	10.0	9.6	9.3	18.9	10.1	18.5	10.2	9.8	9.2	8.9	
NOx, lb/h as NO2	105.0	57.6	105.6	58.1	46.0	36.6	32.4	100.2	52.8	103.9	56.5	42.5	33.9	30.1	
NOx, lb/MBtu (LHV) as NO2 (incl. duct burner fuel)	0.0491	0.0359	0.0490	0.0359	0.0360	0.0359	0.0359	0.0500	0.0359	0.0493	0.0359	0.0359	0.0359	0.0359	
NOx, lb/MBtu (HHV) as NO2 (incl. duct burner fuel)	0.0443	0.0324	0.0442	0.0324	0.0324	0.0324	0.0324	0.0451	0.0324	0.0445	0.0324	0.0324	0.0324	0.0324	
Stack NOx Emissions with the Effects of Selective Catalytic Reduction (SCR)															
NOx, ppmvd (dry, 15% O2)	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	
NOx, ppmvd (dry)	3.4	2.5	3.4	2.5	2.4	2.3	2.3	3.4	2.5	3.4	2.5	2.4	2.2	2.2	
NOx, ppmvw (wet)	3.0	2.3	3.0	2.3	2.2	2.1	2.1	3.0	2.2	3.0	2.3	2.2	2.0	2.0	
NOx, lb/h as NO2	17.1	12.8	17.2	12.9	10.2	8.1	7.2	16.0	11.7	16.8	12.5	9.5	7.5	6.7	
NOx, lb/MBtu (LHV) as NO2 (incl. duct burner fuel)	0.0080	0.0080	0.0080	0.0080	0.0080	0.0080	0.0080	0.0080	0.0080	0.0080	0.0080	0.0080	0.0080	0.0080	
NOx, lb/MBtu (HHV) as NO2 (incl. duct burner fuel)	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	
SCR NH3 slip, ppmvd (dry, 15% O2)	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	
SCR NH3 slip, lb/h	15.8	11.8	15.9	12.0	9.4	7.5	6.7	14.8	10.9	15.6	11.6	8.7	7.0	6.2	
Stack CO Emissions															
CO, ppmvd (dry, 15% O2)	7.6	4.1	7.6	4.1	7.4	7.7	8.0	7.6	4.1	7.6	4.1	7.5	8.0	8.3	
CO, ppmvd (dry)	12.9	5.1	12.9	5.2	9.0	9.0	9.0	13.0	5.1	13.1	5.2	9.0	9.0	9.0	
CO, ppmvw (wet)	11.3	4.6	11.3	4.6	8.2	8.2	8.2	11.4	4.6	11.4	4.6	8.2	8.2	8.2	
CO, lb/h	39.5	16.0	39.8	16.1	23.0	19.1	17.5	37.0	14.6	38.9	15.7	22.0	18.4	17.0	
CO, lb/MBtu (LHV) (incl. duct burner fuel)	0.0185	0.0100	0.0185	0.0100	0.0180	0.0187	0.0194	0.0185	0.0100	0.0185	0.0100	0.0186	0.0195	0.0202	
CO, lb/MBtu (HHV) (incl. duct burner fuel)	0.0166	0.0090	0.0166	0.0090	0.0162	0.0169	0.0175	0.0166	0.0090	0.0166	0.0090	0.0167	0.0176	0.0182	
Stack SO2 Emissions, after SO2 Oxidation															
Assumed SO2 oxidation rate in SCR, vol%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	
SO2, ppmvd (dry, 15% O2)	0.84	0.88	0.84	0.88	0.88	0.88	0.88	0.85	0.88	0.84	0.88	0.88	0.88	0.88	
SO2, ppmvd (dry)	1.43	1.11	1.43	1.11	1.08	1.03	0.99	1.45	1.09	1.45	1.12	1.06	0.99	0.95	
SO2, ppmvw (wet)	1.26	1.00	1.26	1.00	0.98	0.94	0.91	1.27	0.99	1.27	1.00	0.96	0.90	0.87	
SO2, lb/h	10.03	7.86	10.09	7.94	6.27	5.00	4.42	9.43	7.20	9.89	7.71	5.81	4.63	4.11	
SO2, lb/MBtu (LHV) (incl. duct burner fuel)	0.0047	0.0049	0.0047	0.0049	0.0049	0.0049	0.0049	0.0047	0.0049	0.0047	0.0049	0.0049	0.0049	0.0049	
SO2, lb/MBtu (HHV) (incl. duct burner fuel)	0.0042	0.0044	0.0042	0.0044	0.0044	0.0044	0.0044	0.0042	0.0044	0.0042	0.0044	0.0044	0.0044	0.0044	

24-Jan-08 FMPA Cane Island Power Plant Black & Veatch Project 147651 1x1 Emissions Estimates, Revision 1															
Case Number CTG Model CTG Fuel Type CTG Load CTG Inlet Air Cooling CTG Steam/Water Injection Ambient Temperature, F HRSG Duct Firing Fuel Sulfur Content (grains/100 standard cubic feet)	13a PG7241 Natural Gas 100% Off No 73 Fired 2.00	14a PG7241 Natural Gas 100% Off No 73 Unfired 2.00	15a PG7241 Natural Gas 100% Evap. Cooler No 73 Fired 2.00	16a PG7241 Natural Gas 100% Evap. Cooler No 73 Unfired 2.00	17a PG7241 Natural Gas 75% Off No 73 Unfired 2.00	18a PG7241 Natural Gas 50% Off No 73 Unfired 2.00	19a PG7241 Natural Gas 40% Off No 73 Unfired 2.00	20a PG7241 Natural Gas 100% Off No 102 Fired 2.00	21a PG7241 Natural Gas 100% Off No 102 Unfired 2.00	22a PG7241 Natural Gas 100% Evap. Cooler No 102 Fired 2.00	23a PG7241 Natural Gas 100% Evap. Cooler No 102 Unfired 2.00	24a PG7241 Natural Gas 75% Off No 102 Unfired 2.00	25a PG7241 Natural Gas 50% Off No 102 Unfired 2.00	26a PG7241 Natural Gas 40% Off No 102 Unfired 2.00	
Stack Emissions - continued															
Stack UHC Emissions															
UHC, ppmvd (dry, 15% O2)	16.6	6.2	16.5	6.2	6.3	6.6	6.8	17.3	6.3	16.8	6.2	6.5	6.9	7.1	
UHC, ppmvd	28.1	7.7	28.0	7.8	7.7	7.7	7.7	29.7	7.7	28.8	7.8	7.7	7.7	7.7	
UHC, ppmvw	24.8	7.0	24.6	7.0	7.0	7.0	7.0	26.1	7.0	25.1	7.0	7.0	7.0	7.0	
UHC, lb/h as CH4	49.4	13.8	49.5	13.9	11.3	9.4	8.5	48.4	12.8	49.1	13.5	11.0	9.0	8.3	
UHC, lb/MBtu (LHV) (incl. duct burner fuel)	0.0231	0.0086	0.0230	0.0086	0.0088	0.0092	0.0095	0.0241	0.0087	0.0233	0.0086	0.0093	0.0095	0.0099	
UHC, lb/MBtu (HHV) (incl. duct burner fuel)	0.0208	0.0078	0.0207	0.0077	0.0079	0.0083	0.0085	0.0218	0.0078	0.0210	0.0078	0.0084	0.0086	0.0089	
Stack VOC Emissions															
VOC, ppmvd (dry, 15% O2)	1.7	1.2	1.7	1.2	1.3	1.3	1.4	1.8	1.3	1.7	1.2	1.3	1.4	1.4	
VOC, ppmvd (dry)	2.9	1.5	2.9	1.6	1.5	1.5	1.5	3.0	1.5	3.0	1.6	1.5	1.5	1.5	
VOC, ppmvw (wet)	2.6	1.4	2.6	1.4	1.4	1.4	1.4	2.7	1.4	2.6	1.4	1.4	1.4	1.4	
VOC, lb/h as CH4	5.1	2.8	5.2	2.8	2.3	1.9	1.7	4.9	2.6	5.1	2.7	2.2	1.8	1.7	
VOC, lb/MBtu (LHV) (incl. duct burner fuel)	0.0024	0.0017	0.0024	0.0017	0.0018	0.0018	0.0019	0.0025	0.0017	0.0024	0.0017	0.0019	0.0019	0.0020	
VOC, lb/MBtu (HHV) (incl. duct burner fuel)	0.0022	0.0016	0.0022	0.0015	0.0016	0.0017	0.0017	0.0022	0.0016	0.0022	0.0016	0.0017	0.0017	0.0018	
PM10 without the Effects of SO2 oxidation															
PM10 Emissions - Front Half Catch Only															
PM10, lb/h	14.9	9.0	14.9	9.0	9.0	9.0	9.0	14.9	9.0	14.9	9.0	9.0	9.0	9.0	
PM10, lb/MBtu (LHV) (incl. duct burner fuel)	0.0070	0.0056	0.0069	0.0056	0.0070	0.0088	0.0100	0.0074	0.0061	0.0071	0.0057	0.0076	0.0095	0.0107	
PM10, lb/MBtu (HHV) (incl. duct burner fuel)	0.0063	0.0051	0.0063	0.0050	0.0063	0.0080	0.0090	0.0067	0.0055	0.0064	0.0052	0.0068	0.0086	0.0097	
PM10 Emissions - Front and Back Half Catch															
PM10, lb/h	32.2	18.0	32.2	18.0	18.0	18.0	18.0	32.2	18.0	32.2	18.0	18.0	18.0	18.0	
PM10, lb/MBtu (LHV) (incl. duct burner fuel)	0.0151	0.0112	0.0150	0.0111	0.0141	0.0177	0.0199	0.0161	0.0122	0.0153	0.0115	0.0152	0.0191	0.0214	
PM10, lb/MBtu (HHV) (incl. duct burner fuel)	0.0136	0.0101	0.0135	0.0100	0.0127	0.0159	0.0180	0.0145	0.0110	0.0138	0.0103	0.0137	0.0172	0.0193	
PM10 with the Effects of SO2 Oxidation [includes (NH4)2-(SO4)]															
PM10 Emissions - Front Half Catch Only															
PM10, lb/h	14.9	9.0	14.9	9.0	9.0	9.0	9.0	14.9	9.0	14.9	9.0	9.0	9.0	9.0	
PM10, lb/MBtu (LHV) (incl. duct burner fuel)	0.0070	0.0056	0.0069	0.0056	0.0070	0.0088	0.0100	0.0074	0.0061	0.0071	0.0057	0.0076	0.0095	0.0107	
PM10, lb/MBtu (HHV) (incl. duct burner fuel)	0.0063	0.0051	0.0063	0.0050	0.0063	0.0080	0.0090	0.0067	0.0055	0.0064	0.0052	0.0068	0.0086	0.0097	
PM10 Emissions - Front and Back Half Catch															
PM10, lb/h	39.4	22.7	39.5	22.7	21.7	21.0	20.6	38.9	22.3	39.3	22.6	21.5	20.8	20.4	
PM10, lb/MBtu (LHV) (incl. duct burner fuel)	0.0184	0.0141	0.0183	0.0140	0.0170	0.0206	0.0229	0.0194	0.0152	0.0187	0.0144	0.0181	0.0220	0.0244	
PM10, lb/MBtu (HHV) (incl. duct burner fuel)	0.0166	0.0128	0.0165	0.0127	0.0153	0.0185	0.0206	0.0175	0.0137	0.0168	0.0130	0.0163	0.0198	0.0220	
Total Effects of SO2 Oxidation															
Total SO2 to SO3 conversion rate, %vol	25.8%	22.4%	25.8%	22.4%	22.4%	22.4%	22.4%	25.5%	22.4%	25.7%	22.4%	22.4%	22.4%	22.4%	
Total Amount of SO2 converted to SO3, lb/h	3.49	2.27	3.51	2.29	1.81	1.44	1.27	3.23	2.08	3.43	2.23	1.68	1.34	1.19	
Maximum Stack Ammonium Sulfate [(NH4)2-(SO4)] (assuming 100% conversion from SO3), lb/h	7.19	4.68	7.25	4.73	3.73	2.98	2.63	6.65	4.28	7.07	4.59	3.46	2.76	2.45	
Maximum Stack H2SO4 (assuming 100% conversion from SO3 to H2SO4), lb/h	5.34	3.47	5.38	3.51	2.77	2.21	1.95	4.94	3.18	5.24	3.41	2.57	2.05	1.82	

Owner FMPA
Plant Cane Island Power Plant
Project No. 147651.0035
Title 1x1 Emissions Estimates, Revision 1

24-Jan-08 FMPA Cane Island Power Plant Black & Veatch Project 147651 1x1 Emissions Estimates, Revision 1														
Case Number	13a	14a	15a	16a	17a	18a	19a	20a	21a	22a	23a	24a	25a	26a
CTG Model	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241	PG7241
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	Natural Gas	Natural Gas
CTG Load	100%	100%	100%	100%	75%	50%	40%	100%	100%	100%	100%	75%	50%	40%
CTG Inlet Air Cooling	Off	Off	Evap. Cooler	Evap. Cooler	Off	Off	Off	Off	Off	Evap. Cooler	Evap. Cooler	Off	Off	Off
CTG Steam/Water Injection	No	No	No	No	No	No	No	No	No	No	No	No	No	No
Ambient Temperature, F	73	73	73	73	73	73	73	102	102	102	102	102	102	102
HRSG Duct Firing	Fired	Unfired	Fired	Unfired	Unfired	Unfired	Unfired	Fired	Unfired	Fired	Unfired	Unfired	Unfired	Unfired
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	2.00	2.00
Post Combustion Emissions Control Equipment														
Selective Catalytic Reduction (SCR)														
NOx Removed in SCR, %wt	83.8%	77.8%	83.7%	77.8%	77.8%	77.8%	77.8%	84.0%	77.8%	83.8%	77.8%	77.8%	77.8%	77.8%
NOx removed in SCR, lb/h	88.0	44.8	88.4	45.2	35.8	28.5	25.2	84.2	41.1	87.1	43.9	33.1	26.4	23.4
Ammonia Slip, lb/h	15.8	11.8	15.9	12.0	9.4	7.5	6.7	14.8	10.9	15.6	11.6	8.7	7.0	6.2
Notes:	1. The emissions estimates shown in the table above are per stack. 2. These estimates are based on expected CTG/Duct Burner emission guarantees. 3. The dry air composition used is 0.98% Ar, 78.03% N2 and 20.99%O2 4. ISO conditions are defined as 59 F, 14.696 psia and RH of 60%, Norm conditions are defined as 0 C, 1.103 bar 5. All ppm values are based on CH4 calibration gas. 6. The CTG performance is from General Electric dated 11/13/2007. 7. The H2O increase in the SCR catalyst is negligible and not included in the analysis. 8. The VOC/UHC ratios for NG were taken from the GE guarantee used in TCEC Unit 1. 9. Ammonium sulfates created downstream of the SCR are included in the back half particulates. The assumption that 100% SO3 is converted to ammonium sulfates results in "worst case" particulate emissions. 10. Where manufacturer data of lb/h of pollutant emissions were available, the greater of the manufacturer's estimate and B&V's estimate was used in the summary table, i.e. the B&V estimates were adjusted, where applicable. 11. The front half catch of CT particulate emissions is assumed to be half the amount of the front and back half catch. 12. As requested the SCR was designed to reduce the NOx stack emissions to 2 ppmvd@15%O2 when firing NG. 13. The emissions estimate is based on NG with a maximum sulfur content of 2.0 grains/100scf. 14. For the 100% load base and fired cases, a 3% margin on the heat rate was added while a 5% margin was added to the duct burner fuel flow on the fired cases.													

Safe Shutdown Generator Manufacturer Data Sheet



EPA Tier 2 Exhaust Emission Compliance Statement 750DQFAA 60 Hz Diesel Generator Set

Compliance Information:

The engine used in this generator set complies with U.S. EPA and California emission regulations under the provisions of 40 CFR 89, Non-Road (Mobile Off Highway) Tier 2 emissions limits when tested per ISO 8178 D2.

Engine Manufacturer:	Cummins Inc
EPA Certificate Number:	CEX-NRCI-06-40
Effective Date:	12/30/2005
Date Issued:	12/30/2005
EPA Nonroad Diesel Engine Family:	6CEXL030.AAD
CARB Executive Order:	U-R-002-0335

Engine Information:

Model:	Cummins Inc QST30-G5 NR2	Bore:	5.51 in. (140 mm)
Engine Nameplate HP:	1490		
Type:	4 Cycle, 50°V, 12 Cylinder Diesel	Stroke:	6.5 in. (165 mm)
Aspiration:	Turbocharged and Low Temperature Aftercooled (Air-to-Air)	Displacement:	1860 cu. in. (30.5 liters)
Compression Ratio:	14.7:1		
Emission Control Device:	Turbocharged and Low Temperature Aftercooled(Air-to-Air)		

U.S. Environmental Protection Agency Non-Road Tier 2 Limits

COMPONENT	(All values are Grams per HP-Hour)
NOx + HC (Oxides of Nitrogen as NO2 + Total Unburned Hydrocarbons)	4.77
CO (Carbon Monoxide)	2.61
PM (Particulate Matter)	0.15

Engine operation with excessive air intake or exhaust restriction beyond published maximum limits, or with improper maintenance, may result in elevated emission levels.



**Power
Generation**

Exhaust Emission Data Sheet

750DQFAA

60 Hz Diesel Generator Set

Engine Information:

Model:	Cummins Inc. QST30-G5 NR2	Bore:	5.51 in. (139 mm)
Type:	4 Cycle, 50°V, 12 Cylinder Diesel	Stroke:	6.5 in. (165 mm)
Aspiration:	Turbocharged and Low Temperature aftercooled	Displacement:	1860 cu. in. (30.4 liters)
Compression Ratio:	14.7:1		
Emission Control Device:	Aftercooled (Air-to-Air)		

	1/4	1/2	3/4	Full	Full
PERFORMANCE DATA	Standby	Standby	Standby	Standby	Prime
BHP @ 1800 RPM (60 Hz)	276	551	827	1102	999
Fuel Consumption (gal/Hr)	14.8	27.1	39.8	52.7	47.9
Exhaust Gas Flow (CFM)	2350	3620	4930	6310	5880
Exhaust Gas Temperature (°F)	553	686	770	816	798
EXHAUST EMISSION DATA					
HC (Total Unburned Hydrocarbons)	0.22	0.11	0.10	0.09	0.09
NOx (Oxides of Nitrogen as NO ₂)	5.81	4.50	3.83	3.97	3.88
CO (carbon Monoxide)	1.38	0.48	0.37	0.46	0.43
PM (Particular Matter)	0.19	0.17	0.14	0.12	0.13
SO ₂ (Sulfur Dioxide)	0.12	0.11	0.10	0.10	0.10
Smoke (Bosch)	0.65	0.84	0.79	0.79	0.80

All Values are Grams/HP-Hour, Smoke is Bosch #

TEST CONDITIONS

Data was recorded during steady-state rated engine speed (± 25 RPM) with full load ($\pm 2\%$). Pressures, temperatures, and emission rates were stabilized.

Fuel Specification:	46.5 Cetane Number, 0.035 Wt. % Sulfur; Reference ISO8178-5, 40CFR86.1313-98 Type 2-D and ASTM D975 No. 2-D.
Fuel Temperature:	99 $\pm$ 9 °F (at fuel pump inlet)
Intake Air Temperature:	77 $\pm$ 9 °F
Barometric Pressure:	29.6 $\pm$ 1 in. Hg
Humidity:	NOx measurement corrected to 75 grains H ₂ O/lb dry air
Reference Standard:	ISO 8178

The NO_x, HC, CO and PM emission data tabulated here were taken from a single engine under the test conditions shown above. Data for the other components are estimated. These data are subjected to instrumentation and engine-to-engine variability. Field emission test data are not guaranteed to these levels. Actual field test results may vary due to test site conditions, installation, fuel specification, test procedures and instrumentation. Engine operation with excessive air intake or exhaust restriction beyond published maximum limits, or with improper maintenance, may result in elevated emission levels.

Fire Pump Manufacturer Data Sheets

JW6H-UF48

Stationary Fire Pump Engine Driver

EMISSION DATA

EPA 40 CFR Part 60

6 Cylinders
Four Cycle
Lean Burn
Turbocharged & Raw Water Aftercooler

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	290	13.5 (51)	0.30	5.43	0.51	0.13	855 (443)	1506 (43)

Notes:

- 1) 6081HF001 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 PM₁₀.

CLARKE

FIRE PROTECTION PRODUCTS
 3133 EAST KEMPER ROAD
 CINCINNATI, OH 45241

From: Cardinal, Michael
Sent: Wednesday, February 27, 2008 9:11 AM
To: Klote, Lawrence E.
Cc: Armbruster, Stanley A. (Stan)
Subject: Cane Island Fire Pump

Larry,

According to Clarke Fire Protection Products Americas Sales Manager Justin Strousse (513-771-2200 ext 2307), Clarke will be meeting EPA Stationary Fire Pump Requirements 40 CFR Part 60 Sub Part IIII Fed Reg June 28, 2006 standards for year 2009. That would be for NOx limit of 3.0 gm/HP-hr. The technology used would be advanced electronic controls. Clarke will not be able to provide a firm quote until about October due to uncertainty of price at this time.

Regards,

Mike Cardinal P.E.
Black & Veatch Corporation
Energy - Engineering & Construction
Consulting Engineering Services (CES)
11401 Lamar
Overland Park, KS 66211
Phone: (913) 458-6016
e-mail: cardinalm@bv.com

Appendix C

Emission Calculations

FMPA
Cane Island Unit 4 PSD Application
Summary of Potential to Emit for Criteria Pollutants
(Tons per year)

	CO	NO _x	TSP	PM ₁₀	SO ₂	VOC	H ₂ SO ₄	Pb	Hg	Fluorides	H ₂ S	Total Reduced Sulfur
Unit 4 CCCT	178.704	77.088	173.886	173.886	45.289	23.214	24.265	0	0	0	0	0
Safe Shutdown Generator	0.112	0.965	0.029	0.029	0.001	0.066	0.002	0	0	0	0	0
Diesel Engine Fire Pump	0.008	0.050	0.002	0.002	0.000	0.017	0.000	0	0	0	0	0
Cooling Tower	--	--	2.898	2.898	--	--	--	--	--	--	--	--
TOTAL	178.824	78.102	176.816	176.816	45.290	23.298	24.267	0	0	0	0	0
SER	100	40	25	15	40	40	7	0.6	--	3	10	10
PSD Review Required?	YES	YES	YES	YES	YES	NO	YES	NO	--	NO	NO	NO

FMPA

Cane Island Unit 4

Unit 4 CCCT Parameters

Emissions Calculation

Basis:

Unit Type	GE 7FA
Number of Turbines	1
Fuel	Natural Gas
Fuel Burn Rate	1,860.4 MBtu/hr ^[1]

Hours of Operations 8,760 hr/yr

Table C1 Unit 4 CCCT Emissions

Pollutant	Natural Gas		
	Mass Emission (lb/hr)	Potential to Emit (tpy)	[1]
CO	40.8	178.7	[2]
NO _x	17.6	77.1	[2]
PM ₁₀	39.7	173.9	[2]
SO ₂	10.3	45.3	[2]
VOC	5.3	23.2	[2]
H ₂ SO ₄	5.5	24.3	[2]
Lead	0	0.0	[3a]
Mercury	0	0.0	[4]
Fluorides	0	0.0	[4]
H ₂ S	0	0.0	[4, 5]
Total Reduced Sulfur	0	0.0	[4, 5]

Notes []:

1. Based on performance data at 100%, duct firing, evaporative cooling and ISO conditions (59 °F).
2. Performance data contained in Appendix B.
3. USEPA, AP-42, Fifth Edition, Vol. I. Chapter 3 "Stationary Internal Combustion Sources", Section 3.1 "Stationary Gas Turbines". April 2000.
 - a. 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 SO₂ or H₂SO₄.

FMPA

Cane Island Unit 4 PSD Application Safe Shutdown Generator Parameters

Emissions Calculation and Stack Parameters Information

Basis:

Power Rating	1,102 HP ^[1]	
Heat Input	7.38 MBtu/hr	
Heating Value	140,000 Btu/gal ^[2]	
Fuel Burn Rate	53 gal/hr ^[1]	10,540 gal/yr
Hours of Operation	200 hrs/yr	

Stack Exit Conditions ^[1]:

Exhaust Flow Rate	6,310 acfm		
Exhaust Exit Velocity	192.82 ft/sec	58.77 m/sec	
Exhaust Temperature	816 °F	708.71 K	
Stack Diameter	10 in	0.83 ft	0.2540 m
Stack Height	24 ft	7.32 m	

Table C2 Safe Shutdown Diesel Generator Emissions

Pollutant	Outlet Conditions	Emission Rate		Potential to Emit (total)
	g/hp-hr	g/sec	lb/hr	ton/yr
CO	0.46	0.1408	1.1176 ^[1]	1.12E-01
NO _x	3.97	1.2153	9.6451 ^[1]	9.65E-01
PM/PM ₁₀	0.12	0.0367	0.2915 ^[1]	2.92E-02
SO ₂	4.58E-03	0.0014	0.0111 ^[3]	1.11E-03
VOC	0.09	0.0837	0.6640 ^[1]	6.64E-02
H ₂ SO ₄	0.01	0.0021	0.0170 ^[5]	1.70E-03
Lead	0	0	0 ^[6]	0.00E+00
Mercury	0	0	0 ^[6]	0.00E+00
Fluorides	0	0	0 ^[6]	0.00E+00
H ₂ S	0	0	0 ^[6]	0.00E+00
Total Reduced Sulfur	0	0	0 ^[6]	0.00E+00

Operating Scenarios:

24-hr per day worst case operation assumed

Table C3 Emergency 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	1.408E-01	1.118E+00	--	--	1.408E-01	1.118E+00	--	--	--	--
NO _x	--	--	--	--	--	--	--	--	2.775E-02	2.202E-01
PM/PM ₁₀	--	--	--	--	--	--	3.673E-02	2.915E-01	8.387E-04	6.656E-03
SO ₂	--	--	1.403E-03	1.113E-02	--	--	1.403E-03	1.113E-02	3.203E-05	2.542E-04

Notes []:

- Vendor data - Cummins Model 750DQFAA
- 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.
- Ultra low sulfur fuel oil, 0.0015%(wt).
- USEPA, AP-42, Fifth Edition, Vol. I. Chapter 3 "Stationary Internal Combustion Sources", Section 3.4 "Large Stationary Diesel and All Stationary Dual-fuel Engines". October 1996.
 - Table 3.4-1 "Gaseous Emission Factors for Large Stationary Diesel and All Stationary Dual-Fuel Engines".
- Assumed 100% conversion of SO₂ to H₂SO₄.
- Emissions are insignificant and assumed to be zero.

FMPA

Cane Island Unit 4 PSD Application

Diesel Engine Fire Pump Parameters

Emissions Calculation and Stack Parameters Information

Basis:

Power Rating	290 BHP ^[1]	
Heat Input	1.89 MBtu/hr	
Heating Value	140,000 Btu/gal ^[2]	
Fuel Burn Rate	13.5 gal/hr ^[1]	702 gal/yr
Hours of Operation	52 hrs/yr	

Stack Exit Conditions ^[1]:

Exhaust Flow Rate	1,506 acfm		
Exhaust Exit Velocity	184.08 ft/sec	56.11 m/sec	
Exhaust Temperature	855 °F	730.37 K	
Stack Diameter	5 in	0.42 ft	0.13 m
Stack Height	15.17 ft	4.62 m	

Table C4 Fire Pump Emissions

Pollutant	Outlet Conditions	Emission Rate		Potential to Emit
	g/bhp-hr	g/sec	lb/hr	ton/yr
CO	0.51	0.0411	0.3261 ^[1]	8.48E-03
NO _x	3.00	0.2417	1.9180 ^[1]	4.99E-02
PM/PM ₁₀	0.13	0.0105	0.0831 ^[1]	2.16E-03
SO ₂	4.46E-03	0.0004	0.0029 ^[3]	7.42E-05
VOC	1.03	0.0833	0.6615 ^[4a]	1.72E-02
H ₂ SO ₄	0.01	0.0006	0.0044 ^[5]	1.14E-04
Lead	0	0	0 ^[6]	0.00E+00
Mercury	0	0	0 ^[6]	0.00E+00
Fluorides	0	0	0 ^[6]	0.00E+00
H ₂ S	0	0	0 ^[6]	0.00E+00
Total Reduced Sulfur	0	0	0 ^[6]	0.00E+00

Operating Scenarios:

1-hr per day operation (fire pump operating for testing purposes only)

Table C5 Emergency 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	4.108E-02	3.261E-01	--	--	5.135E-03	4.076E-02	--	--	--	--
NO _x	--	--	--	--	--	--	--	--	1.435E-03	1.139E-02
PM/PM ₁₀	--	--	--	--	--	--	4.363E-04	3.463E-03	6.216E-05	4.934E-04
SO ₂	--	--	1.198E-04	9.508E-04	--	--	1.497E-05	1.188E-04	2.133E-06	1.693E-05

Notes []:

1. Vendor data - Clarke Model JW6H-UF48 (1760 RPM).
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. USEPA, AP-42, Fifth Edition, Vol. I. Chapter 3 "Stationary Internal Combustion Sources", Section 3.3 "Gasoline and Diesel Industrial Engines". October 1996.
 - a. Table 3.3-1 "Emission Factors for Uncontrolled Gasoline and Diesel Industrial Engines".
5. Assumed 100% conversion of SO₂ to H₂SO₄.
6. Emissions are insignificant and assumed to be zero.

FMPA

Cane Island Unit 4 PSD Application

Cooling Tower - Linear Mechanical Draft

Cooling Tower Emissions

Basis (per Tower):

Total Dissolved Solids	476 mg/L	
Cycles of Concentration	5 No.	
Cycled Water TDS	2,380 ppmw	
Drift Rate	0.0005 %	
Cell Diameter	30 ft	
Stack Height	56 ft	
Circulating Water Flow	111,130 gpm	
Exhaust Air Flow (per cell)	1,003,756 cfm	4,374.08 kg/s
Number of Cells (per tower)	8 No.	
Number of Towers	1 No.	
Ambient Pressure	14.70 psia	
Relative Humidity	60 %	
Wet Bulb Temperature	69 °F	
Heat Dissipation Rate	861 MBtu/hr	
Enthalpy of air _{in} (H _{in})	33.08 Btu/lb	

PM ₁₀ /TSP Fraction	1.000 dimensionless	[1]
PM _{2.5} /PM ₁₀ Fraction	0.600 dimensionless	[2a]

Calculations:

TSP Emission (lb/hr) = Circulating Water Flow Rate (gpm) x (Drift Rate(%)/100) x Density of Circulating Water (lb/gal) x TDS (ppmw) x 60 min/h
TSP Emission (tpy) = TSP Emission (lb/hr) x Operating Hours (hrs/yr) x 1 ton/2,000 lb

PM₁₀ Emission (lb/hr) = TSP Emission (lb/hr) x PM₁₀/TSP Fraction
PM₁₀ Emission (tpy) = PM₁₀ Emission (lb/hr) x Operating Hours (hrs/yr) x 1 ton/2,000 lb

PM_{2.5} Emission (lb/hr) = PM₁₀ Emission (lb/hr) x PM_{2.5}/PM₁₀ Fraction
PM_{2.5} Emission (tpy) = PM_{2.5} Emission (lb/hr) x Operating Hours (hrs/yr) x 1 ton/2,000 lb

Table C6 Cooling Tower Emissions

Activity	Number of Towers No.	Hours of Operation hr/yr	Circulating Water Flow gpm	Drift Rate %	Density Circ Water lb/gal	TDS ppmw	Potential Uncontrolled Emissions			Control Method	Control Efficiency %	Potential Controlled Emissions		
							tpy					tpy		
							TSP	PM10	PM2.5			TSP	PM10	PM2.5
Cooling Tower - Mechanical Draft	1	8,760	111,130	0.0005	8.34	2,380	2.90	2.90	1.74	NA	0	2.90	2.90	1.74

Calculations (for modeling):

Exit Velocity (per cell) 23.67 ft/sec = 7.21 m/sec

Enthalpy of air_{out} (H_{out}) 57.89 Btu/lb

Exit Temperature (dry bulb) 91.52 °F = 33.07 °C = 306.22 °K

Guess Temp

91.5 °F

Table C7 Cooling Tower Modeling Parameters

EU Number	Activity	Cells per Tower No.	Controlled Emissions (per cell)			Controlled Emissions (per cell)		
			lb/hr			g/sec		
			TSP	PM10	PM2.5	TSP	PM10	PM2.5
	Cooling Tower - Mechanical Draft	8	0.0827	0.0827	0.0496	0.0104	0.0104	0.0063

Notes []:

- Assumed all particulate emissions are less than 10 microns.
- South Coast AQMD, Air Guidance Book "Methodology to Calculate Particulate Matter (PM) 2.5 and PM 2.5 Significance Thresholds". Final. October 2006.
 - Table A "Updated CEIDARS Table with PM2.5 Fractions".

FMPA

Cane Island Unit 4 PSD Application

Unit 4 CCCT

Hazardous Air Pollutants (HAPs) Emissions Calculation

Basis:

Unit Type	GE 7FA
Number of Turbines	1
Fuel	Natural Gas
Fuel Burn Rate	1,860.4 MBtu/hr ^[1]
Hours of Operations	8,760 hr/yr

Table C8 Unit 4 CCCT HAPs Emissions

Pollutant	Natural Gas		Potential to Emit (tpy)
	Emission Factor (lb/MBtu)	Mass Emission (lb/hr)	
Organic HAP Emissions			
1,3-Butadiene	4.3E-07 ^[2a]	8.0E-04	0.004
Acetaldehyde	4.0E-05 ^[2a]	7.4E-02	0.326
Acrolein	6.4E-06 ^[2a]	1.2E-02	0.052
Benzene	1.2E-05 ^[2a]	2.2E-02	0.098
Ethylbenzene	3.2E-05 ^[2a]	6.0E-02	0.261
Formaldehyde	7.1E-04 ^[2a]	1.3E+00	5.785
Naphthalene	1.3E-06 ^[2a]	2.4E-03	0.011
PAH	2.2E-06 ^[2a]	4.1E-03	0.018
Propylene Oxide	2.9E-05 ^[2a]	5.4E-02	0.236
Toluene	1.3E-04 ^[2a]	2.4E-01	1.059
Xylenes	6.4E-05 ^[2a]	1.2E-01	0.522
Total Organic HAP Emissions			8.371

Notes []:

1. Based on performance data at 100% and ISO conditions (59 °F).
2. USEPA, AP-42, Fifth Edition, Vol. I. Chapter 3 "Stationary Internal Combustion Sources", Section 3.1 "Stationary Gas Turbines". April 2000.
 - a. Table 3.1-3 "Emission Factors for Hazardous Air Pollutants from Natural Gas-Fired Stationary Gas Turbines".

FMPA

Cane Island Unit 4 PSD Application Duct Burner

Hazardous Air Pollutants (HAPs) Emissions Calculation

Basis:

Fuel	Natural Gas
Fuel Burn Rate	593.2 MBtu/hr ^[1]
Heating Value	1,020 Btu/scf
Hours of Operations	8,760 hr/yr
Number of Burners	1

Table C9 Duct Burner HAPs Emissions

Pollutant	Natural Gas		Potential to Emit (tpy)
	Emission Factor	Mass Emission (lb/hr)	
Organic HAP Emissions ^[2a]			
2-Methylnaphthalene	2.4E-05 lb/mmscf	1.4E-05	6.1E-05
3-Methylchloranthrene	1.8E-06 lb/mmscf	1.0E-06	4.6E-06
7,12-Dimethylbenz(a)anthracene	1.6E-05 lb/mmscf	9.3E-06	4.1E-05
Acenaphthene	1.8E-06 lb/mmscf	1.0E-06	4.6E-06
Acenaphthylene	1.8E-06 lb/mmscf	1.0E-06	4.6E-06
Anthracene	2.4E-06 lb/mmscf	1.4E-06	6.1E-06
Benz(a)anthracene	1.8E-06 lb/mmscf	1.0E-06	4.6E-06
Benzene	2.1E-03 lb/mmscf	1.2E-03	5.3E-03
Benzo(a)pyrene	1.2E-06 lb/mmscf	7.0E-07	3.1E-06
Benzo(b)fluoranthene	1.8E-06 lb/mmscf	1.0E-06	4.6E-06
Benzo(g,h,i)perylene	1.2E-06 lb/mmscf	7.0E-07	3.1E-06
Benzo(k)fluoranthene	1.8E-06 lb/mmscf	1.0E-06	4.6E-06
Chrysene	1.8E-06 lb/mmscf	1.0E-06	4.6E-06
Dibenzo(a,h)anthracene	1.2E-06 lb/mmscf	7.0E-07	3.1E-06
Dichlorobenzene	1.2E-03 lb/mmscf	7.0E-04	3.1E-03
Fluoranthene	3.0E-06 lb/mmscf	1.7E-06	7.6E-06
Fluorene	2.8E-06 lb/mmscf	1.6E-06	7.1E-06
Formaldehyde	7.5E-02 lb/mmscf	4.4E-02	1.9E-01
Hexane	1.8E+00 lb/mmscf	1.0E+00	4.6E+00
Indeno(1,2,3-cd)pyrene	1.8E-06 lb/mmscf	1.0E-06	4.6E-06
Naphthalene	6.1E-04 lb/mmscf	3.5E-04	1.6E-03
Phenanthrene	1.7E-05 lb/mmscf	9.9E-06	4.3E-05
Pyrene	5.0E-06 lb/mmscf	2.9E-06	1.3E-05
Toluene	3.4E-03 lb/mmscf	2.0E-03	8.7E-03
Total Organic HAP Emissions			4.795
Metallic HAP Emissions ^[2b]			
Arsenic	2.0E-04 lb/mmscf	1.2E-04	0.001
Beryllium	1.2E-05 lb/mmscf	7.0E-06	0.000
Cadmium	1.1E-03 lb/mmscf	6.4E-04	0.003
Chromium	1.4E-03 lb/mmscf	8.1E-04	0.004
Cobalt	8.4E-05 lb/mmscf	4.9E-05	0.000
Manganese	3.8E-04 lb/mmscf	2.2E-04	0.001
Mercury	2.6E-04 lb/mmscf	1.5E-04	0.001
Nickel	2.1E-03 lb/mmscf	1.2E-03	0.005
Selenium	2.4E-05 lb/mmscf	1.4E-05	0.000
Total Metallic HAP Emissions			0.014
Total HAP Emissions			4.809

Notes []:

- Based on performance data at 100% and iso conditions (59 °F).
- USEPA, AP-42, Fifth Edition, Vol. I. Chapter 1 "External Combustion Sources", Section 1.4 "Natural Gas Combustion". July 1998.
 - Table 1.4-3 "Emission Factors for Speciated Organic Compounds from Natural Gas Combustion".
 - Table 1.4-4 "Emission Factors for Metals from Natural Gas Combustion".

FMPA

Cane Island Unit 4 PSD Application Safe Shutdown Generator

Hazardous Air Pollutants (HAPs) Emissions Calculation

Basis:

Fuel	ULS Fuel Oil
Fuel Burn Rate	7.4 MBtu/hr ^[1]
Hours of Operations	200 hr/yr
Number of Generators	1

Table C10 Safe Shutdown Generator HAPs Emissions

Pollutant	ULSD Fuel Oil		Potential to Emit (tpy)
	Emission Factor (lb/MBtu)	Mass Emission (lb/hr)	
Organic HAP Emissions			
Acetaldehyde	2.52E-05 ^[2a]	1.9E-04	1.9E-05
Acrolein	7.88E-06 ^[2a]	5.8E-05	5.8E-06
Benzene	7.76E-04 ^[2a]	5.7E-03	5.7E-04
Formaldehyde	7.89E-05 ^[2a]	5.8E-04	5.8E-05
Toluene	2.81E-04 ^[2a]	2.1E-03	2.1E-04
Xylenes	1.93E-04 ^[2a]	1.4E-03	1.4E-04
PAH	2.12E-04 ^[3]	1.6E-03	1.6E-04
Acenaphthylene	9.23E-06 ^[2b]	--	--
Acenaphthene	4.68E-06 ^[2b]	--	--
Naphthalene	1.30E-04	--	--
Fluorene	1.28E-05 ^[2b]	--	--
Phenanthrene	4.08E-05 ^[2b]	--	--
Anthracene	1.23E-06 ^[2b]	--	--
Fluoranthene	4.03E-06 ^[2b]	--	--
Pyrene	3.71E-06 ^[2b]	--	--
Benz(a)anthracene	6.22E-07 ^[2b]	--	--
Chrysene	1.53E-06 ^[2b]	--	--
Benzo(b)fluoranthene	1.11E-06 ^[2b]	--	--
Benzo(k)fluoranthene	2.18E-07 ^[2b]	--	--
Benzo(a)pyrene	2.57E-07 ^[2b]	--	--
Indeno(1,2,3-cd)pyrene	4.14E-07 ^[2b]	--	--
Dibenz(a,h)anthracene	3.46E-07 ^[2b]	--	--
Benzo(g,h,i)perylene	5.56E-07 ^[2b]	--	--
Total Organic HAP Emissions			1.16E-03

Notes []:

- Based on vendor data (52.7 gal/hr) and a heating value of 140,000 Btu/gal.
- USEPA, AP-42, Fifth Edition, Vol. I. Chapter 3 "Stationary Internal Combustion Sources", Section 3.4 "Large Stationary Diesel and All Stationary Dual-fuel Engines". October 1996.
 - Table 3.4-3 "Speciated Organic Compound Emission Factors for Large Uncontrolled Stationary Dies
 - Table 3.4-4 "PAH Emission Factors for Large Uncontrolled Stationary Diesel Engines".

FMPA

Cane Island Unit 4 PSD Application

Fire Pump

Hazardous Air Pollutants (HAPs) Emissions Calculation

Basis:

Fuel	ULS Fuel Oil
Fuel Burn Rate	1.89 MBtu/hr ^[1]
Hours of Operations	52 hr/yr
Number of Pumps	1

Table C11 Fire Pump HAPs Emissions

Pollutant	ULSD Fuel Oil		Potential to Emit (tpy)
	Emission Factor (lb/MBtu)	Mass Emission (lb/hr)	
Organic HAP Emissions			
1,3-Butadiene	3.91E-05 [2a]	7.4E-05	1.9E-06
Acetaldehyde	7.67E-04 [2a]	1.4E-03	3.8E-05
Acrolein	9.25E-05 [2a]	1.7E-04	4.5E-06
Benzene	9.33E-04 [2a]	1.8E-03	4.6E-05
Formaldehyde	1.18E-03 [2a]	2.2E-03	5.8E-05
Toluene	4.09E-04 [2a]	7.7E-04	2.0E-05
Xylenes	2.85E-04 [2a]	5.4E-04	1.4E-05
PAH	1.68E-04 [3]	3.2E-04	8.3E-06
Acenaphthene	1.42E-06 [2a]	--	--
Acenaphthylene	5.06E-06 [2a]	--	--
Anthracene	1.87E-06 [2a]	--	--
Benzo(a)anthracene	1.68E-06 [2a]	--	--
Benzo(a)pyrene	1.88E-07 [2a]	--	--
Benzo(b)fluoranthene	9.91E-08 [2a]	--	--
Benzo(g,h,i)perylene	4.89E-07 [2a]	--	--
Benzo(k)fluoranthene	1.55E-07 [2a]	--	--
Chrysene	3.53E-07 [2a]	--	--
Dibenz(a,h)anthracene	5.83E-07 [2a]	--	--
Fluoranthene	7.61E-06 [2a]	--	--
Fluorene	2.92E-05 [2a]	--	--
Indeno(1,2,3-cd)pyrene	3.75E-07 [2a]	--	--
Naphthalene	8.48E-05 [2a]	--	--
Phenanthrene	2.94E-05 [2a]	--	--
Pyrene	4.78E-06 [2a]	--	--
Total Organic HAP Emissions			1.90E-04

Notes []:

- Based on vendor data (13.5 gal/hr) and a heating value of 140,000 Btu/gal.
- USEPA, AP-42, Fifth Edition, Vol. I. Chapter 3 "Stationary Internal Combustion Sources", Section 3.3 "Gasoline and Diesel Industrial Engines". October 1996.
 - Table 3.3-2 "Speciated Organic Compound Emission Factors for Uncontrolled Diesel Engines".
- Summation of individual PAH chemicals.

FMPA

Cane Island Unit 4 PSD Application

Project Total

Hazardous Air Pollutants (HAPs) Emissions Calculation

Table C12 Project HAPs Emissions

Pollutant	Potential to Emit				
	Unit 4 CCCT	Duct Burner	Safe Shutdown Generator	Fire Pump	Project Total ^[1]
	(tpy)	(tpy)	(tpy)	(tpy)	(tpy)
Organic HAP Emissions					
1,3-Butadiene	3.5E-03	--	--	1.9E-06	3.51E-03
2-Methylnaphthalene	--	6.1E-05	--	--	6.11E-05
3-Methylchloranthrene	--	4.6E-06	--	--	4.59E-06
7,12-Dimethylbenz(a)anthracene	--	4.1E-05	--	--	4.08E-05
Acenaphthene	--	4.6E-06	--	--	4.59E-06
Acenaphthylene	--	4.6E-06	--	--	4.59E-06
Acetaldehyde	3.3E-01	--	1.9E-05	3.8E-05	3.26E-01
Acrolein	5.2E-02	--	5.8E-06	4.5E-06	5.22E-02
Anthracene	--	6.1E-06	--	--	6.11E-06
Benz(a)anthracene	--	4.6E-06	--	--	4.59E-06
Benzene	9.8E-02	5.3E-03	5.7E-04	4.6E-05	1.04E-01
Benzo(a)pyrene	--	3.1E-06	--	--	3.06E-06
Benzo(b)fluoranthene	--	4.6E-06	--	--	4.59E-06
Benzo(g,h,i)perylene	--	3.1E-06	--	--	3.06E-06
Benzo(k)fluoranthene	--	4.6E-06	--	--	4.59E-06
Chrysene	--	4.6E-06	--	--	4.59E-06
Dibenzo(a,h)anthracene	--	3.1E-06	--	--	3.06E-06
Dichlorobenzene	--	3.1E-03	--	--	3.06E-03
Ethylbenzene	2.6E-01	--	--	--	2.61E-01
Fluoranthene	--	7.6E-06	--	--	7.64E-06
Fluorene	--	7.1E-06	--	--	7.13E-06
Formaldehyde	5.8E+00	1.9E-01	5.8E-05	5.8E-05	5.98E+00
Hexane	--	4.6E+00	--	--	4.59E+00
Indeno(1,2,3-cd)pyrene	--	4.6E-06	--	--	4.59E-06
Naphthalene	1.1E-02	1.6E-03	--	--	1.21E-02
PAH	1.8E-02	--	1.6E-04	8.3E-06	1.81E-02
Phenanthrene	--	4.3E-05	--	--	4.33E-05
Propylene Oxide	2.4E-01	--	--	--	2.36E-01
Pyrene	--	1.3E-05	--	--	1.27E-05
Toluene	1.1E+00	8.7E-03	2.1E-04	2.0E-05	1.07E+00
Xylenes	5.2E-01	--	1.4E-04	1.4E-05	5.22E-01
Total Organic HAP Emissions					13.168
Metallic HAP Emissions					
Arsenic	--	5.1E-04	--	--	5.09E-04
Beryllium	--	3.1E-05	--	--	3.06E-05
Cadmium	--	2.8E-03	--	--	2.80E-03
Chromium	--	3.6E-03	--	--	3.57E-03
Cobalt	--	2.1E-04	--	--	2.14E-04
Manganese	--	9.7E-04	--	--	9.68E-04
Mercury	--	6.6E-04	--	--	6.62E-04
Nickel	--	5.3E-03	--	--	5.35E-03
Selenium	--	6.1E-05	--	--	6.11E-05
Total Metallica HAP Emissions					0.014
Total HAP Emissions					13.182

Notes []:

1. Total HAP emissions are the total HAP emissions from the combustion turbine, the duct burner operation, safe shutdown generator, and the fire pump.

Appendix D
BACT Analysis

**Best Available Control Technology Analysis
for
FMPA – Cane Island Power Park
Unit 4
Combined Cycle Combustion Turbine**

**Submitted by
Florida Municipal Power Agency**

**April 2008
Project No. 147651**



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Attachment 1 NO_x Control Technology Review List

Attachment 2 CO Control Technology Review List

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Acronym List

AQC	Air Quality Control
BACT	Best Available Control Technology
bhp	Brake Horsepower
BOP	Balance-of-Plant
Btu	British Thermal Unit
CAA	Clean Air Act
CEMS	Continuous Emissions Monitoring System
CFR	Code of Federal Regulations
CO	Carbon Monoxide
CCCT	Combined Cycle Combustion Turbine
CT	Combustion Turbine
CTG	Combustion Turbine Generator
DB	Duct Burner
DLN	Dry Low NO _x Burner
FDEP	Florida Department of Environmental Protection
FGD	Flue Gas Desulfurization
FMPA	Florida Municipal Power Agency
FPL	Florida Power & Light Company
H ₂	Hydrogen
H ₂ S	Hydrogen Sulfide
H ₂ SO ₄	Sulfuric Acid Mist
h/yr	Hours per Year
HHV	Higher Heating Value
HRSG	Heat Recovery Steam Generator
in. wg	Inches Water Gauge
ISO	International Organization for Standardization
K ₂ CO ₃	Potassium Carbonate
kW	Kilowatt
kWh	Kilowatt Hour
LAER	Lowest Achievable Emission Rate
Lb/h	Pound per Hour
LNB	Low NO _x Burner
MBtu	Million British Thermal Unit
MW	Megawatt
NESCAUM	Northeast States for Coordinated Air Use Management

ng/J	Nanogram per Joule
NO	Nitrogen Oxide
NO ₂	Nitrogen Dioxide
NO _x	Nitrogen Oxides
NSPS	New Source Performance Standard
NSR	New Source Review
O&M	Operations and Maintenance
OAQPS	Office of Air Quality Planning And Standards
Pb	Lead
PEC	Purchased Equipment Costs
PM/PM ₁₀	Particulate Matter/Particulate Matter Less than 10 Microns
ppm	Parts per Million
ppmvd	Parts per Million Volumetric Dry
PSD	Prevention of Significant Deterioration
RACT	Reasonably Available Control Technology
RBLC	RACT/BACT/LAER Clearinghouse
RH	Relative Humidity
SARA	Superfund Amendments and Reauthorization Act of 1986
Scf	Standard Cubic Feet
SCR	Selective Catalytic Reduction
SNCR	Selective Noncatalytic Reduction
SO ₂	Sulfur Dioxide
SO ₃	Sulfur Trioxide
STG	Steam Turbine Generator
TCI	Total Capital Investment
tpy	Tons per Year
ULSFO	Ultra-Low Sulfur Fuel Oil
USEPA	United States Environmental Protection Agency
VOC	Volatile Organic Compound

1.0 Introduction and Executive Summary

Florida Municipal Power Agency (FMPA) proposes to expand the Cane Island Power Park by adding a new, high-efficiency, natural gas fired electric generating unit. The new electric generating unit, known as Cane Island Unit 4 (also referred to as the “Unit 4”) will be located in Osceola County, southwest of Orlando, Florida, and west of Kissimmee, Florida. Unit 4 will consist of a 1x1 General Electric F-Class (PG7241FA) Combined Cycle Combustion Turbine (CCCT) and associated support facilities. Unit 4 will be fueled with natural gas as the primary fuel with no alternate backup fuel. Unit 4 will include a 150 megawatt (MW) (approximate) combustion turbine generator (CTG), a duct fired heat recovery steam generator (HRSG), and a 150 MW (approximate) steam turbine generator (STG). The Project includes Cane Island Unit 4, a diesel engine driven fire pump, a safe shutdown generator, and a mechanical draft cooling tower.

The Project is classified as a New Source Review/Prevention of Significant Deterioration (NSR/PSD) major modification to an existing major source, and as a result of the calculated emissions increases, is subject to a Best Available Control Technology (BACT) review for sulfur dioxide (SO₂), nitrogen oxides (NO_x), carbon monoxide (CO), particulate matter/particulate matter less than 10 microns (PM)/PM₁₀, and sulfuric acid mist (H₂SO₄), as previously discussed in Section 2.4 of the air permit application document. The Project is not subject to review for volatile organic compounds (VOC), lead (Pb), hydrogen sulfide (H₂S), vinyl chloride, total fluorides, mercury, or total reduced sulfur compounds.

As required under the NSR/PSD regulations, the BACT analysis presented herein employed 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 the Cane Island Unit 4 CCCT, diesel engine driven fire pump, safe shutdown generator, and mechanical draft cooling tower. 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.

1.1 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.

1.2 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.

1.3 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.

1.4 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.

1.5 Step 5--Select BACT

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

As summarized in Table 1-1, the aforementioned BACT analysis process resulted in the following control technology and emissions level determinations for the Project's affected air emissions sources and pollutants. The ton per year (tpy) emissions presented in Appendix C are proposed as BACT emission caps.

Table 1-1
BACT Determination Summary

Emission Unit: Nominal 300 MW CCCT Unit B (1x1 F-Class PG7241FA)				
Pollutant	Control Technology	Emission Basis	Compliance Method	CEMS Avg Period
NO _x	DLN/SCR	2.0 ppmvd at 15% O ₂	Stack Test, Three-Run Avg	24 hour block
CO	Good Combustion Controls	7.6 ppmvd at 15% O ₂ with DBs 4.1 ppmvd at 15% O ₂ w/o DBs 8.0 ppmvd at 15% O ₂ with and w/o DBs	Stack Test, Three-Run Avg	24 hour block
PM/PM ₁₀	Natural Gas (2.0 gr S/100 scf) Good Combustion Practices	10% Opacity	USEPA Method 9 Fuel Sulfur Records	NA
SO2	Natural Gas (2.0 gr S/100 scf)	NA	Fuel Sulfur Records	NA
H ₂ SO ₄	Natural Gas (2.0 gr S/100 scf)	NA	Fuel Sulfur Records	NA
Emission Unit: Safe Shutdown Generator (750 kW)				
Pollutant	Control Technology			
SO ₂	Ultra low-sulfur fuel oil (ULSFO)			
NO _x	Good Combustion Controls			
PM/PM ₁₀	ULSFO			
CO	Good Combustion Controls			
VOC	Good Combustion Controls			
H ₂ SO ₄	ULSFO			
Emission Unit: Emergency Fire Pump (290 bhp)				
Pollutant	Control Technology			
SO ₂	ULSFO			
NO _x	Good Combustion Controls			
PM/PM ₁₀	ULSFO			
CO	Good Combustion Controls			
VOC	Good Combustion Controls			
H ₂ SO ₄	ULSFO			
Emission Unit: Cooling Tower				
Pollutant	Control Technology	Emission Basis		
PM/PM ₁₀	Drift Eliminators	0.0005 percent drift rate		
CEMS = Continuous Emissions Monitoring System. DB = Duct burners. DLN = Dry low NO _x . gr S/100 scf = Grains of sulfur/100 standard cubic feet.		MBtu = Million British Thermal Unit. ppmvd = Parts per million volumetric dry. SCR = Selective Catalytic Reduction. ULSFO = Ultra-low sulfur fuel oil		

2.0 BACT Analysis Basis

This section describes the basis of the Project, Cane Island Power Park Unit 4, 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 Cane Island Unit 4 is 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 Florida Electrical Power Plant Siting Act (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 follows:

“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).

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 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 (Code of Federal Regulations) 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 a new stationary CCCT, Unit 4 will be subject to NSPS Subpart KKKK. Additionally, because the Project is subject to Subpart KKKK, it is not subject to Subpart GG or Subpart Da for the combustion turbine (CT) and HRSG DBs, respectively. Applicable NSPS Subpart KKKK emissions limitations for the Project are as follows:

- NO_x--15 ppm (parts per million) at 15 percent O₂ or 54 ng/J (nanograms per joule) of useful output (0.43 lb/MWh [pound per megawatt-hour]) – new turbines firing natural gas 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.

2.1.1.2 NSPS Subpart III – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines. The Project's safe shutdown generator and emergency fire pump will be subject to the manufacturer's certification requirements of compliance to NSPS Subpart III. 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 proposed operating scenario for the Project is a maximum of 8,760 full load operating hours per year (h/yr) while firing natural gas with or without DB firing on natural gas. This unit is expected to cycle with frequent startups and will be operated at 40 to 100 percent of full load for up to 8,760 h/yr.

2.2.1 CCCT Cane Island Unit 4

Table 2-1 presents the BACT design basis for the Project's CCCT. Table 2-2 shows the baseline emission rates for Cane Island Unit 4 at 100 percent base load at the International Organization for Standardization (ISO) inlet air temperature of 59° F for natural gas and 60 percent relative humidity (60 percent RH), hereinafter referred to as ISO conditions. The emissions shown in Table 2-2 are based on the use of DLN burners during natural gas firing with the operation of the natural gas fired DBs at 100 percent load. The DBs will fire only natural gas. The lb/MBtu values are based on the higher heating value (HHV) of the expected fuel to be fired and are based on the combined heat input to the CT and the DBs. Table 2-3 shows the uncontrolled emissions for Cane Island Unit 4.

Table 2-1 Combustion Turbine Design Basis ^(a)	
Size	Nominal 300 MW (combined cycle)
CTG	
Heat Input	1,860.4 MBtu/h ^(a)
HRSG DBs	
Heat Input	593.2 MBtu/h ^(a)
Operating Hours	8,760 h/yr
Fuel	Natural Gas
^(a) Based on the HHV when firing natural gas, 100 percent load, duct firing, evaporative cooling, at ISO conditions.	

Table 2-2 Baseline Emission Rates for Cane Island Unit 4	
Emission Parameter	Unit 4 ^(a) Natural Gas, 100% Load, Duct Firing, Evaporative Cooling at ISO Conditions
NO _x , ppmvd at 15% O ₂	12.2
NO _x , lb/h	107.7
NO _x , lb/MBtu (HHV)	0.0439
CO, ppmvd at 15% O ₂	7.6
CO, lb/h	40.8
CO, lb/MBtu (HHV)	0.0166
PM/PM ₁₀ (front and back), lb/h ^(b)	39.7
PM/PM ₁₀ (front and back), lb/MBtu (HHV) ^(c)	0.0162
SO ₂ , lb/h ^(c)	10.34
SO ₂ , lb/MBtu (HHV) ^(c)	0.0042
H ₂ SO ₄ , lb/h ^(b)	5.54
H ₂ SO ₄ , lb/MBtu ^(b)	0.00298
^(a)Emissions are based on firing natural gas in the CT and HRSG DBs at 100 percent of base load with evaporative cooling at ISO conditions. ^(b)PM/PM₁₀ and H₂SO₄ values include the effects of 20 percent SO₂ oxidation in the CT and 10 percent SO₂ oxidation in the DBs. ^(c)SO₂ values include the effects of 3 percent SO₂ oxidation in the SCR System. Based on a natural gas sulfur content of 2.0 grains/100 scf.	

Table 2-3 Cane Island Unit 4 Baseline Uncontrolled Emissions	
Emission Parameter	Natural Gas Firing ^(a)
NO _x , tpy	471.73
CO, tpy	178.8
PM/PM ₁₀ (front and back), tpy	173.89
SO ₂ , tpy	45.29
H ₂ SO ₄ , tpy	24.27
^(a) Cane Island Unit 4 emissions are based on firing natural gas in the CT and HRSG DBs at 100 percent of base load with evaporative cooling at ISO conditions.	

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	2.3
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)	50
Natural Gas Cost, \$/MBtu (2008)	8.05
Aqueous Ammonia Cost, \$/ton (2008)	215
Energy Cost, \$/kWh (2008)	0.063
Sales Tax, percent	NA

3.0 Cane Island Unit 4 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 Cane Island Unit 4. As this analysis will demonstrate, the proposed NO_x BACT was determined to be the use of SCR to achieve an emission limit of 2 ppmvd at 15 percent O₂ while firing natural gas. The proposed CO BACT was determined to be the use of good combustion controls while firing natural gas.

3.1 Step 1--Identify All NO_x 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 NO_x emissions limit that is being evaluated. The results of this search for all CCCTs are listed in Attachment 1: NO_x Control Technology Review List.

NO_x is defined as the combination of nitrogen oxide (NO) and nitrogen dioxide (NO₂). Typically, the NO_x that is formed in CTs consists of 60 percent NO, with the balance occurring as NO₂. 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.

NO_x 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.
 - DLN Burners.
 - XONON.

- Post-Combustion Type:
 - Selective Noncatalytic Reduction (SNCR).
 - SCONO_x.
 - 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 Unit 4 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 CT. A limit exists, however, on the amount of water that can be injected into the system before reliability of the CT 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. Furthermore, this in-combustor control technology is typically used for fuel oil fired CTs or much smaller units.

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 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 CTs. 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 Noncatalytic 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 temperature at the exit of the CT is between 1,074° to 1,200° 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*

A second, post-combustion technology from EmeraChem, LLC is EM_xTM (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 (H₂) (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 (K₂CO₃) to oxidize both NO_x and CO, thereby reducing total plant emissions. CO emissions are decreased by the oxidation of CO to CO₂. The catalyst is installed in the flue gas at a point where the temperature is between 300° to 700° F. 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 SO₂ is oxidized to sulfur trioxide (SO₃) by the SCOSO_x catalyst. The SO₃ 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 K₂CO₃ 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 CCCT 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 was apprehensive about applying SCONO_x technology to large combined cycle turbines that burn primarily natural gas. The CT proposed for this project is approximately 150 MW, which is outside the operating range (32 MW) of the SCONO_x system currently operating at the Federal Cold Storage Cogeneration facility in California.

3.1.6 Selective Catalytic Reduction

Another post-combustion method of NO_x control is SCR. SCR systems have been used quite extensively in CTG/HRSG projects for the past 10 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 CT 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 to 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. For Unit 4, the flue gas temperature in the HRSG of the CTG/HRSG would typically range from 600° to 800° F. Accordingly, a vanadium/titanium catalyst can be installed for Unit 4. 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 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. 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 ammonia, 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 in this BACT analysis to control NO_x emissions.

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. The results of this search for all CCCTs are listed in Attachment 2: CO Control Technology Review List.

Typically, measures taken to minimize the formation of NO_x during combustion inhibit complete combustion, which increases the emissions of CO. CO 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 CT. High combustion temperatures, adequate excess air, and good air/fuel mixing during combustion minimize CO emissions.

CO 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:
 - 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 (LNBs) 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 CO₂. 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 73.7 percent CO reduction rate (i.e., 7.6 ppm to 2.0 ppm) has been assumed for 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 CO₂. The demonstrated application for this technology is currently limited to CCCT units under 40 MW. The CT proposed for this project is approximately 150 MW, which is outside the operating range (32 MW) of the SCONO_x system currently operating at the Federal Cold Storage Cogeneration facility 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.

Table 3-1 Summary of Step 2--Eliminate Technically Infeasible Options		
Technology Alternative	Technically Feasible (Yes/No)	
	Available	Applicable
Water or Steam Injection	Yes	No – Wet injection has limited NO _x removal. Not a primary control technology for natural gas fired turbines.
DLN Burners	Yes	Yes
XONON	Yes	No – There are no documented installations on utility sized CTs firing natural gas.
SNCR	Yes	No – The exhaust temperature of the CT is less than the SNCR's optimum temperature range.
SCONO _x	Yes	Yes
SCR	Yes	Yes

3.3.1 Water or Steam Injection

Water or steam injection can be an effective NO_x control method for a turbine burning natural gas or fuel oil. However, demineralized water must be used and additional capital cost is required because an onsite demineralized system must be built and the annual operation of this system can be a significant expense in the unit operation. The development of DLN burners has replaced the use of wet controls, except for certain cases, such as oil firing. New DLN burners can achieve lower levels of NO_x compared to wet controls. Since Unit 4 will only fire natural gas, water injection will not be considered further in this BACT analysis.

3.3.2 Dry Low NO_x Burners

DLN burners are a demonstrated technology for controlling NO_x emissions from a CCCT and are commercially available from several vendors. DLN 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) CT, it has not been applied to utility size CTs such as proposed for Unit 4. It is expected that application of this technology to utility size CTs 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 CTs firing natural gas, it is not considered to be technically feasible for Unit 4. As such, this method of combustion control will be eliminated from further evaluation for control of NO_x emissions in this BACT analysis.

3.3.4 Selective Noncatalytic 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 CT is between 1,074° to 1,200° 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.

3.3.5 SCONO_x

The application of this technology is currently limited to natural gas CCCT units under 40 MW. However, EmeraChem, LLC is EM_xTM (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 NO_x control.

3.3.6 Selective Catalytic Reduction

SCR systems are a demonstrated technology of controlling NO_x emissions from a CCCT and commercially available from several vendors. SCR systems are considered technically feasible and will be considered further.

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 CT and commercially available from several vendors. DLN burners and good combustion control are considered technically feasible and will be considered further.

3.4.2 CO Oxidation Catalyst

CO oxidation catalysts are a demonstrated technology of controlling CO emissions from a simple cycle CT and are commercially available from several vendors. CO oxidation catalysts 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

3.4.3 SCONO_x

The application of this technology is currently limited to natural gas CCCT units under 40 MW. However, EmeraChem, LLC is EM_xTM (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 DLN burners is the least stringent control technology considered for Cane Island Unit 4. However, the use of a combination SCR/oxidation catalyst system or the SCONO_x system are technologies capable of achieving significantly lower emissions than the application of DLN 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:

- In-combustor NO_x and CO control consisting of DLN combustors to limit outlet emissions during natural gas firing for all operating loads for Unit 4 is considered the base case scenario. All modern CTs of the type proposed for this Project include DLN combustors.

- The addition of an SCR system and oxidation catalyst to reduce outlet NO_x emissions from the natural gas fired CTG/HRSG with DB to the level of 2.0 ppmvd and CO to 2.0 ppmvd emissions for the natural gas fired CTG/HRSG with DBs.
- The addition of a SCONO_x system to reduce outlet NO_x emissions from the natural gas fired CTG/HRSG with DBs to the NO_x level of 2.0 ppmvd and CO emissions to 2.0 ppmvd.

The following evaluation considers energy, environmental, and economic impacts for the NO_x and CO combined technology scenarios evaluated. Table 3-3 outlines the expected NO_x and CO emissions rates from the evaluated emissions control alternatives of DLN burners (i.e., good combustion controls), SCR/CO catalyst, and SCONO_x. SCR/CO catalyst and SCONO_x are considered the most stringent NO_x and CO emissions control alternatives because 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 a BACT evaluation would be done for control of NO_x and CO emissions separately.

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 Cane Island Unit 4. The following are the evaluated technologies: SCONO_x, SCR, and Oxidation Catalyst.

3.6.1 SCONO_x Energy Impacts

The use of an SCONO_x system will increase the energy requirements on the system compared to use of DLN burners alone. The SCONO_x system will increase the back pressure on the CT by about 4 inches water gauge (in. wg). This will reduce the output of Cane Island Unit 4 by approximately 0.3 percent and increase the lost power generation. In addition, the period required for catalyst washing will result in increasing the lost power generation. Wahlco-Metroflex estimated the unit will be off-line 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 CT. These three effects will be added together to

Table 3-3 Estimated NO _x and CO Emissions from Alternate Control Technologies for Unit 4			
	Control Technology Alternatives		
	LNB/Good Combustion Controls	SCR/CO Catalyst	SCONO _x
NO _x Emissions			
ppmvd (at 15 percent O ₂)	12.2	2.0	2.0
pounds per hour (lb/h)	107.7	17.6	17.6
tpy ^(a)	471.7	77.3	77.3
percent reduction	NA	83.6	83.6
NO _x Emission Reduction (tpy)	Base	394.4	394.4
CO Emissions			
ppmvd (at 15 percent O ₂)	7.6	2.0	2.0
lb/h	40.8	10.7	10.7
tpy ^(a)	178.7	47.0	47.0
percent reduction	NA	73.7	73.7
CO Emission Reduction (tpy)	Base	131.7	131.7
^(a) Total emissions are based on 8,760 h/yr firing natural gas, 100 percent load, duct firing, evaporative cooling, at ISO conditions.			

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 K₂CO₃. When the K₂CO₃ coating can no longer be regenerated, the precious metal content of the remaining catalyst can be recycled. Although recycling the K₂CO₃ 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 CO₂, a greenhouse gas. There is currently a worldwide effort to reduce industrial emissions of CO₂ because of its contribution to global climate change. Installation of a SCONO_x system would directly counter this initiative.

The SCONO_x catalyst will oxidize approximately 1.0 percent of the SO₂ in the flue gas to SO₃. The SO₃ will then react with the moisture in the flue gas to form H₂SO₄ in the atmosphere. Any H₂SO₄ formed will increase the amount of PM emitted in the flue gas. The PM will predominately consist of PM₁₀.

3.6.3 SCR Energy Impacts

The use of an SCR system impacts the energy requirements of Cane Island Unit 4. 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 back pressure on each CT. The SCR system would add about 2.6 in. wg back pressure to the unit for the NO_x reduction to 2.0 ppmvd. This would reduce the output of Cane Island Unit 4 by approximately 492 kilowatts (kW).

3.6.4 SCR Environmental Impacts

The vanadium content of the SCR catalyst contributes to its classification as a hazardous waste. Therefore, spent catalyst may need to be handled and disposed of following hazardous waste procedures. 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:

<u>Human Response</u>	<u>Concentration (ppm)</u>
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 Cane Island Unit 4 stack is 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, Florida Department of Environmental Protection (FDEP) proposed an ammonia slip of 5 ppmvd for Treasure Coast, a CCCT unit utilizing SCR. Based on the recent Treasure Coast air permit, an ammonia slip design value of 5 ppmvd at 15 percent O₂ is used for this analysis.

The SCR catalyst will oxidize approximately 2 to 3 percent of the SO₂ in the flue gas to SO₃. Once the flue gas cools below approximately 600° F, the ammonia present in the flue gas may react with SO₃ 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 SO₃ will react with the moisture in the flue gas to form H₂SO₄ in the atmosphere. Any ammonium sulfate and bisulfate salts and sulfuric acid mist formed will increase the

amount of PM emitted in the flue gas. The particulate material will predominately consist of matter less than PM₁₀. 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 Cane Island Unit 4.

3.6.5 Oxidation Catalyst Energy Impacts

An oxidation catalyst reactor located downstream of the CT exhaust will increase the back pressure on the CT. The additional back pressure of about 1.2 in. wg, will reduce each CT output by approximately 227 kW. The cost of lost power revenue due to the back pressure 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 SO₂ in the flue gas will oxidize to SO₃. The higher the operating temperature, the higher the SO₂ to SO₃ oxidation potential. It is estimated that approximately 20 percent of the SO₂ in the flue gas will oxidize to SO₃ as a result of the oxidation catalyst being installed after the CT outlet with high temperatures. The SO₃ will react with the moisture in the flue gas to form H₂SO₄. The increase in H₂SO₄ emissions would increase PM₁₀ 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 back pressure 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 CO₂, a greenhouse gas. There is currently a worldwide effort to reduce industrial emissions of CO₂ because of its contribution to global climate change. Installation of an oxidation catalyst would directly counter this initiative.

3.6.7 Economic Impacts for SCR (2.0 ppmvd)/Oxidation Catalyst Versus SCONO_x

The use of an SCR/oxidation catalyst or SCONO_x has significant economic impacts to Cane Island Unit 4. An analysis of the economic impact is provided in this subsection.

3.6.7.1 Capital Costs for SCR (2.0 ppmvd)/Oxidation Catalyst and SCONO_x.

Table 3-4 presents the capital costs for installing an SCR/oxidation catalyst and SCONO_x system on Cane Island Unit 4 during natural gas firing to achieve an NO_x outlet emission level of 2.0 ppmvd and a CO outlet emission rate of 2.0 ppmvd. The cost of the SCR/oxidation catalyst system includes the ammonia receiving, storage, transfer, vaporization, and injection; catalytic reactor housing and ductwork; controls and instrumentation; and freight. The catalyst costs were not included in the total capital investment (TCI) cost but were 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 balance-of-plant (BOP) cost for the SCR/oxidation catalyst and SCONO_x system consists 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 BOP items such as foundations, insulation and lagging, and painting and were calculated as percentages of the total purchased equipment costs. The TCI was calculated as the summation of the total direct cost and total indirect costs in accordance with OAQPS cost methods. The indirect capital costs for the SCR/oxidation catalyst systems are percentages of the total direct costs and are site specific. The indirect capital costs for the SCONO_x system are percentages of the SCONO_x system direct costs.

Table 3-4 NO _x /CO Combined Control Alternative Capital Cost (\$) For Cane Island Unit 4				
	DLN	SCONO _x (\$)	SCR/ Oxidation Catalyst (\$)	Remarks
Direct Capital Cost				Cost based on emissions in Table 3-3.
Catalysts	NA	Included	1,289,000	Est. from BASF/CERAM.
Catalyst Reactor Housing /Ductwork	NA	Included	705,000	Estimated from Turner EnviroLogic.
SCONO _x System	NA	16,000,000	0	Vendor Estimate.
Control/Instrumentation	NA	150,000	195,000	Estimated; includes controls and monitoring equipment.
Ammonia (Storage and Injection)	NA	N/A	985,000	Estimated from Turner EnviroLogic and previous projects.
PEC	NA	16,150,000	3,174,000	
Sales Tax		0	0	Not applicable to FMPA.
Freight	NA	1,615,000	318,000	10 percent of PEC.
BOP	NA	5,491,000	953,000	30 percent of PEC. Refer to text for background information on this item.
Total Direct Cost (DC)	NA	23,256,000	4,445,000	
Indirect Capital Costs				
Contingency	NA	2,326,000	445,000	10 percent of DC.
Engineering and Supervision	NA	2,326,000	445,000	10 percent of DC for SCONO _x , 10 percent of DC for SCR and 10 percent of DC for CO catalyst.
Construction and Field Expense	NA	1,163,000	223,000	5 percent of DC.
Construction Fee	NA	2,326,000	445,000	10 percent of DC.
Startup Assistance	NA	465,000	89,000	2 percent of DC.
Performance Test	NA	50,000	50,000	Assumed \$50,000 emission test.
Total Indirect Capital Costs (IC)	Base	8,656,000	1,697,000	
Installed Costs (DC+IC)	Base	31,912,000	6,142,000	
Less Catalyst	Base	4,000,000	1,289,000	Catalyst is viewed as an operations and maintenance (O&M) value.
TCI	Base	27,912,000	4,853,000	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 lists 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 subsection, the TCI for the SCR/oxidation catalyst control system is calculated as the sum of the total direct and indirect capital costs in accordance with OAQPS cost methods. The TCI for Cane Island Unit 4 controlling NO_x and CO to 2.0 ppmvd and 2.0 ppmvd, respectively, is estimated to be \$4,853,000.

The TCI for the SCONO_x control system is calculated as the sum of the total direct and indirect capital costs in accordance with OAQPS cost methods. The TCI for Cane Island Unit 4 controlling NO_x and CO to 2.0 ppmvd and 2.0 ppmvd, respectively, is estimated to be \$27,912,000.

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 SO₂ 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.

3.6.7.2 Operating Costs for SCR/Oxidation Catalyst Versus SCONO_x.

Table 3-5 presents the annualized operating costs using an 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 for Unit 4. 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 routine 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 3 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 back-pressure losses. The additional back pressure will derate the CT 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 an 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.

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 Workers' 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 for combining these overhead costs 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 TCI for each system.

Table 3-5
NO_x/CO Combined Control Alternative Annualized Cost (\$) For Cane Island Unit 4

	DLN	SCONO _x (\$)	SCR/ Oxidation Catalyst (\$)	Remarks
Direct Annual Cost				Cost based on emissions in Table 3-3.
Catalyst Replacement	NA	1,116,000	536,000	Includes freight, installation, and 3 year capital recovery factor based on 3 year guaranteed catalyst life for SCR/oxidation catalyst and 5 year catalyst life for SCONO _x .
O&M	NA	64,000	37,000	Refer to text for background information on this item.
Maintenance Materials	NA	48,000	23,000	
Reagent Feed	NA	N/A	240,000	Assumes 1.1 stoichiometric ratio.
Natural Gas Consumption	NA	65,000	0	
Power Consumption	NA	110,000	285,000	Includes injection blower and vaporization of ammonia.
Lost Power Generation	NA	2,191,000	397,000	Back pressure on CT. Includes 7 days of lost power generation time for catalyst/system cleaning for SCONO _x .
Annual Distribution Check	NA	116,000	34,000	Estimated as 0.5 percent of the total direct cost for SCONO _x and 1 percent for SCR.
Total Direct Annual Cost	NA	3,710,000	1,552,000	
Indirect Annual Costs				
Overhead	NA	38,000	22,000	60 percent of O&M cost.
Administrative Charges	NA	638,000	123,000	2 percent of installed cost.
Property Taxes	NA	0	0	Not included.
Insurance	NA	319,000	61,000	1 percent of installed cost.
Capital Recovery	NA	2,240,000	389,000	Capital recovery excluding catalyst.
Total Indirect Annual Costs	NA	3,235,000	595,000	
Total Annualized Cost	NA	6,945,000	2,147,000	

3.6.7.3 Total Annualized Costs for SCR (2 ppmvd)/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 and the TCI. Table 3-5 shows that the total annualized cost for an SCR/oxidation catalyst system for Cane Island Unit 4 firing natural gas is estimated to be \$2,147,000, which is approximately a third of the cost of an SCONO_x system having a total annualized cost of \$6,945,000.

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, the SCONO_x 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

This section identifies economic impacts of the NO_x only BACT analysis. This section will not include a discussion of energy and environmental impacts, because 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

The control of NO_x emissions separate from CO emission control is possible through the application of an SCR to Cane Island Unit 4 without additional CO emission controls. To determine the BACT levels for NO_x controls without the influence of the CO emission controls, a separate economic analysis is required. An analysis of the economic impact of SCR as a separate control technology for NO_x emissions of 2.0 ppmvd firing natural gas is provided in this subsection. The BACT costs presented in this analysis are based on operating the CT, with duct firing, at 100 percent base load for 8,760 h/yr on natural gas.

3.7.2 Economic Impacts for SCR (2.0 ppmvd NO_x) System

The use of an SCR has significant economic impacts to the FMFA Project. The application of SCR on Cane Island Unit 4 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 (2.0 ppmvd NO_x). Table 3-6 summarizes the economic capital cost for implementing SCR on Cane Island Unit 4 firing natural gas. Based on the analysis in this subsection, the total installed capital costs for the SCR control system is calculated as the sum of the total direct and indirect capital costs in accordance with OAQPS cost methods. The TCI cost of SCR for Cane Island Unit 4 controlling NO_x to 2.0 ppmvd is estimated to be \$4,031,000.

3.7.2.2 Total Annualized Costs for SCR (2.0 ppmvd NO_x). 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 and the TCI. Table 3-7 shows that the total annualized cost for SCR systems is estimated to be \$1,676,000. This annualized cost for the Unit 4 SCR systems results in a cost-effectiveness of approximately \$4,250 per ton of NO_x removed.

3.8 Step 4--Evaluate Most Effective CO Controls

This section identifies economic impacts of the CO only BACT analysis. This section will not include a discussion of energy and environmental impacts, because 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 FMPA Project. An analysis of the economic impact is provided in this subsection. An analysis of the economic impact of oxidation catalyst as a separate control technology for CO emissions of 2.0 ppmvd firing natural gas is provided in this subsection. The BACT costs presented in this analysis are based on operating the CT, with duct firing, at 100 percent of base load for 8,760 h/yr on natural gas.

Table 3-6
NO_x Emission Control Alternative Capital Cost (\$) for Cane Island Unit 4

	DLN	SCR (\$)	Remarks
Direct Capital Cost			Cost based on emissions in Table 3-3.
Catalyst	N/A	674,000	Estimated from CERAM.
Catalyst Reactor Housing/Ductwork	N/A	630,000	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.
PEC	N/A	2,439,000	
Sales Tax		0	Not applicable to FMPPA.
Freight	N/A	244,000	10 percent of PEC.
BOP	N/A	732,000	30 percent of PEC. Refer to text for background information on this item.
Total Direct Cost (DC)	Base	3,415,000	
Indirect Capital Costs			
Contingency	N/A	342,000	10 percent of DC.
Engineering and Supervision	N/A	342,000	10 percent of DC.
Construction and Field Expense	N/A	171,000	5 percent of DC.
Construction Fee	N/A	342,000	10 percent of DC.
Startup Assistance	N/A	68,000	2 percent of DC.
Performance Test	N/A	25,000	Assumed \$25,000.
Total Indirect Capital Costs (IC)	Base	1,290,000	
Installed Costs (DC + IC)		4,705,000	
Less SCR Catalyst Cost		674,000	Catalyst is viewed as an O&M value.
TCI	Base	4,031,000	

Table 3-7
NO_x Emissions Control Annualized Cost (\$) for Cane Island Unit 4

	DLN	SCR (\$)	Remarks
Direct Annual Cost			Cost based on emissions in Table 3-3.
Catalyst Replacement	NA	299,000	Includes freight, installation, and 3 year capital recovery factor based on 3 year guaranteed catalyst life.
O&M	NA	37,000	Refer to text for background information.
Maintenance Materials	NA	23,000	Refer to text for background information.
Reagent Feed	NA	240,000	Assumes 1.1 stoichiometric ratio.
Power Consumption	NA	285,000	Includes injection blowers and vaporization of ammonia.
Lost Power Generation	NA	272,000	Back pressure on CT.
Annual Distribution Check	NA	34,000	Estimated as 1 percent of the total direct cost.
Total Direct Annual Cost	NA	1,190,000	
Indirect Annual Costs	NA		
Overhead	NA	22,000	60 percent of O&M cost.
Administrative Charges	NA	94,000	2 percent of installed costs.
Property Taxes	NA	0	Not included.
Insurance	NA	47,000	1 percent of installed costs.
Capital Recovery	NA	323,000	Capital recovery excluding catalyst.
Total Indirect Annual Cost	NA	486,000	
Total Annualized Cost	NA	1,676,000	
NO _x Annual Emissions, tpy	471.3	77.3	Emissions taken from Table 3-3.
NO _x Emissions Reduction, tpy	NA	374.4	Emissions calculated in Table 3-3.
NO _x Total Cost Effectiveness, \$/ton	NA	4,250	Total Analyzed Cost/Emissions Reduction.

3.8.2 Capital Cost for Oxidation Catalyst

Table 3-8 presents the capital cost for installing an oxidation catalyst on the units during natural gas firing to achieve a CO outlet emission level of 2.0. The capital costs for the systems include 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 BOP items such as foundations, insulation and lagging, and painting, and were calculated as percentages of the total PEC. The TCI was calculated as the summation of the total direct cost and total indirect costs in accordance with OAQPS cost methods. The indirect capital costs for the SCR/oxidation catalyst systems are percentages of the total direct cost and are site specific. The 3 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 Subsection 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 TCI per unit for an oxidation catalyst system to reduce CO emissions from Cane Island Unit 4 firing natural gas is estimated to be \$822,000.

3.8.3 Operating Costs for Oxidation Catalyst

Table 3-9 presents the annualized operating costs and emission rates using an oxidation catalyst to achieve a 74 percent reduction in CO emissions while firing natural gas on Cane Island Unit 4. Annualized operating costs for the system include catalyst replacement and lost power generation. Throughout the life of the plant, catalyst elements will require routine periodic replacement. Currently, catalyst manufacturers are willing to guarantee an oxidation catalyst life of 3 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 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 and the total installed costs. Firing natural gas, the total annualized cost for a 2.0 ppmvd CO oxidation catalyst system for Cane Island Unit 4 is estimated to be \$471,000. This annualized cost for Cane Island Unit 4 results in a cost-effectiveness of approximately \$3,576 per ton of CO removed.

Table 3-8
CO Reduction System Capital Cost (\$) For Cane Island Unit 4

	Good Combustion Controls/DLN	Oxidation Catalyst (\$)	Remarks
Direct Capital Cost			Cost based on emissions in Tables 3-3.
Oxidation Catalyst	NA	615,000	Estimated from BASF.
Catalyst Reactor Housing	NA	75,000	
Control/Instrumentation	NA	45,000	Estimated; includes controls and monitoring equipment.
PEC	NA	735,000	
Sales Tax	NA	0	Not applicable to FMPPA.
Freight	NA	74,000	10 percent of PEC.
BOP	NA	221,000	30 percent of PEC. Refer to text for background information on this item.
Total Direct Cost (DC)	Base	1,030,000	
Indirect Capital Costs	NA		
Contingency	NA	103,000	10 percent of DC.
Engineering and Supervision	NA	103,000	10 percent of DC.
Construction and Field Expense	NA	52,000	5 percent of DC.
Construction Fee	NA	103,000	10 percent of DC.
Startup Assistance	NA	21,000	2 percent of DC.
Performance Test	NA	25,000	Assumed value of \$25,000.
Total Indirect Capital Costs (IC)	Base	407,000	
Installed Costs (DC +IC)		1,437,000	
Less Catalyst	NA	615,000	Catalyst is viewed as an O&M value.
Total Capital Investment, TCI	Base	822,000	

Table 3-9
CO Control Annualized Cost (\$) For Cane Island Unit 4

	Good Combustion Controls/DLN	Oxidation Catalyst (\$)	Remarks
Direct Annual Cost			Cost based on emissions in Tables 4-1.
Catalyst Replacement	NA	237,000	Includes freight, installation, and 3 year capital recovery factor based on 3 year guaranteed catalyst life.
O&M	NA	0	Not applicable for oxidation catalyst.
Lost Power Generation		125,000	Back pressure on CT.
Total Direct Annual Cost	NA	362,000	
Indirect Annual Costs			
Overhead	NA	0	Not applicable because of zero O&M.
Administrative Charges	NA	29,000	2 percent of installed costs.
Property Taxes	NA	0	Not included.
Insurance	NA	14,000	1 percent of installed costs.
Capital Recovery	NA	66,000	Capital recovery excluding catalyst.
Total Indirect Annual Costs	NA	109,000	
Total Annualized Cost	Base	471,000	
CO Annual Emissions, tpy	178.7	47.0	Emissions taken from Table 3-3.
CO Emissions Reduction, tpy	NA	131.7	Emissions taken from Table 3-3.
CO Total Cost Effectiveness, \$/ton	NA	3,576	Total Annualized Cost/Emissions Reduction

3.9 Step 5--Select NO_x BACT

Based on the cost-effectiveness value for the SCR catalyst it is determined that add-on controls to further reduce NO_x emissions are warranted. FMPA has determined that the top NO_x control alternative when firing natural gas, DLN burners with SCR catalyst, represents NO_x BACT for Cane Island Unit 4, corresponding to an emissions limit of 2 ppmvd at 15 percent O₂ on a 24 hour average basis. Table 3-10 summarizes the Project's NO_x BACT determination for Cane Island Unit 4.

Table 3-10 Cane Island Unit 4 NO _x BACT Determination	
Control Technology	Emission Limit
DLN Burners with SCR	2.0 ppmvd at 15 percent O ₂ (24 hour average)

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 Cane Island Unit 4 firing natural gas. As a basis for review, the cost-effectiveness guidelines are pollutant-specific, considering the control technology, environmental sensitivity, and determinations from similar BACT trends for that pollutant in the affected region and across the country. FMPA believes that an oxidation catalyst is not BACT for this project. This determination is independent of the NO_x control determination. The CO BACT assessment is firmly based on the energy, environmental, and economic impacts detailed in the application, as well as recent Department determinations for similar units at similar emission levels. In those determinations, the Department has found that add-on controls to further reduce CO emissions are unwarranted given the already low emissions characteristics of this particular gas turbine firing natural gas as the only fuel. A few of those particular determinations are Florida Power & Light's (FPL's) Turkey Point, TECO's Bayside Power Station, FMPA's Treasure Coast, and Progress Energy's Hines Power Block 4, which are all documented in Attachment 2. The CO BACT cost-effectiveness for FMPA has determined that the CO BACT for Cane Island Unit 4 during natural gas firing, with and without the operation of the natural gas fired DBs at 100 percent load, is good combustion controls. The CO BACT emission limit, with and without DBs operating, is a stack test limit of 7.6 ppmvd at 15 percent O₂ and 4.1 ppmvd at 15 percent O₂, respectively. The CEMS average limit is proposed as 8 ppmvd at 15 percent O₂, and

24 hour block average. Table 3-11 summarizes the Project's CO BACT determination for Cane Island Unit 4.

Table 3-11 Cane Island Unit 4 CO BACT Determination	
Control Technology	Emission Limit
Good Combustion Controls	7.6 ppmvd at 15 percent O ₂ (stack test, three-run average) with DBs 4.1 ppmvd at 15 percent O ₂ (stack test, three-run average) without DBs 8 ppmvd at 15 percent O ₂ (CEMS, 24 hour block average)

4.0 Cane Island Unit 4 PM/PM₁₀ BACT Analysis

The objective of this analysis was to determine BACT for PM/PM₁₀ emissions from Cane Island Unit 4. This includes the CT and supplemental firing from DBs in the HRSG as a total unit.

PM/PM₁₀ emissions from the CTs are a result of incomplete combustion and trace particulate parameters in the fuel. The emissions of PM from Cane Island Unit 4 will be controlled by ensuring as complete combustion of the fuel as possible. The NSPS for CTs does not establish a particulate emission limit. Natural gas contains only trace quantities of noncombustible 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 PM control technologies being used on CTs. 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 PM and is proposed for Cane Island Unit 4.

5.0 Cane Island Unit 4 SO₂ BACT Analysis

The objective of this analysis was to determine BACT for SO₂ emissions from Cane Island Unit 4. The SO₂ emissions are based on operating the CT with duct firing at 100 percent of baseload for a total of 8,760 hours while firing natural gas.

Typically, natural gas has only trace amounts of sulfur that is used as an odorant. The selection of natural gas fuel provides inherently low SO₂ emissions.

Emissions of SO₂ can be controlled by limiting sulfur content in the fuel, limiting fuel oil usage, or by a post-combustion flue gas desulfurization (FGD) system. The fuel for this project is natural gas with a maximum expected sulfur content of 2.0 grains per 100 standard cubic feet.

To date, no supplemental SO₂ emission controls, such as FGD systems, have been imposed on simple cycle CTs. Such a system would be both technically and economically prohibitive.

Therefore, BACT for Cane Island Unit 4 is the use of natural gas. The basis of this determination is firing natural gas up to a maximum of 8,760 h/yr.

6.0 Cane Island Unit 4 H₂SO₄ BACT Analysis

The objective of this analysis was to determine BACT for H₂SO₄ emissions from Cane Island Unit 4. The H₂SO₄ emissions are based on operating the CT with duct firing at 100 percent of baseload for a total of 8,760 hours while firing natural gas.

Emissions of H₂SO₄ can be controlled by limiting sulfur content in the fuel. The natural gas to be utilized for Cane Island Unit 4 will contain less than 2 grains per 100 scf. The selection of low sulfur fuel (natural gas) provides inherently low SO₂ emissions, thus controlling the formation of H₂SO₄. In addition, no supplemental SO₃ emission controls, such as FGD systems or H₂SO₄ abatement systems, have been imposed on natural gas fired CTs by regulatory agencies.

Therefore, BACT for Cane Island Unit 4 is the use of good combustion controls while firing natural gas. The basis of this determination is firing natural gas up to a maximum of 8,760 h/yr.

7.0 Cane Island Unit 4 Safe Shutdown Generator and Fire Pump BACT Analysis

In the event of the loss of normal auxiliary power, ac power will be supplied by a new 750 kW, ULSFO fired safe shutdown generator. Additionally, a new emergency fire pump will supply emergency fire water to the Project using a 290 bhp diesel engine. The fire pump will be periodically tested for no more than 1 hour per week (up to 52 h/yr) to confirm their ready-to-start condition. The safe shutdown generator will be limited to no more than 200 hours per year of operation. Because of their small size, 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 SO₂, or oxidation catalyst for CO, while technically feasible for the safe shutdown generator and the fire pump, are far from cost-effective as control devices and are, therefore, not practical as BACT control alternatives. As such, FMPA has determined that BACT for the safe shutdown 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 SO₂ BACT

The safe shutdown generator and fire pump will emit small quantities of SO₂ as a result of the oxidation of sulfur in the fuel. A review of the informational databases discussed in Section 2.1 indicates 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 a low sulfur fuel oil. Therefore, ULSFO is proposed as the BACT. The BACT control is good combustion control and combustion of 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 2.1.1.4, 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/PM₁₀ BACT

The safe shutdown 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 safe shutdown generator and the fire pump, good combustion control and engine design are proposed as BACT.

As discussed in Subsection 2.1.1.4, 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 safe shutdown generator and the 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 safe shutdown generator.

As discussed in Subsection 2.1.1.4, 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 H₂SO₄ BACT

The safe shutdown generator and the fire pump will emit small quantities of H₂SO₄ as a result of the oxidation of SO₂ 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 Cane Island Unit 4 Cooling Tower

A new multicell linear mechanical draft cooling tower will be used to dissipate heat from the condensing water of the Project's main boiler. Particulate from cooling towers is generated by the presence of dissolved and suspended solids in the cooling tower circulation water, which is potentially lost as "drift" or moisture droplets that are suspended in the air moving out of the cooling tower. A portion of the water droplets emitted from the tower exhausts will evaporate, leaving the suspended or dissolved solids in the atmosphere.

The particulate emissions from the cooling towers can be controlled by minimizing the amount of water drift that occurs and/or minimizing the amount of dissolved solids in the water. This can be accomplished by using high efficiency drift eliminators, a decreased number of cycles of circulating water concentration, or a combination of both. The number of cycles of water concentration is limited by the amount of water available for use, since lower levels of concentration require increased cooling tower blowdown and more water intake to offset the blowdown.

A review of drift eliminators as particulate control technology for cooling towers concluded that they are technically feasible. There are no significant energy, environmental, or economic impacts that would preclude the use of drift eliminators as particulate control technologies as presented in this evaluation.

The proposed cooling tower BACT for this Project is the use of drift eliminators for particulate control, with a cooling tower design drift rate of 0.0005 percent.

Attachment 1
NO_x Control Technology Review List

NO _x Top Down RBLC Clearinghouse Review Results Table A-1												
FACILITY/COMPANY	STATE	FUEL	New (MW)	# of CCCTs	# of DBs	Turbine Model	LIMIT (LB/MBTU)	AVG PERIOD	CONTROL TECHNOLOGY	STATUS	COMMENTS	DATA SOURCE
Barton Shoals Energy, LLC	AL	NG	1,200	4	4	GE 7FA (170 MW)	2.5 ppm (0.0092 lb/mmbtu)		SCR	07/15/2002	EPA did not received application until 5/24/02	EPA Region 4 and 7 CT Spreadsheet
Dome Valley Energy Partners -- Wellton Mohawk Generation Station	AZ	NG	310	1	1	GE 7FA	2 ppm @ 15% O2	3-hr	DLN, SCR	12/01/2004	After 18 months, the 3-hour average changes to 1-hr average unless it is demonstrated it can not be met.	RBLC
Salt River Project -- Santan Generating Plant	AZ	NG	900	3	3	GE 7FA	2 ppm @ 15% O2	1-hr	SCR	03/07/2003		RBLC
Caithness Blythe II, LLC -- Blythe Energy Project II	CA	NG	580	2	2	GE 7FA (170 MW)	2.0 ppmdv @ 15% O2	3-hr	SCR	04/25/2007		RBLC
Calpine Western Regional -- Pastoria Energy Facility	CA	NG	750	3			2.5 ppm @ 15% O2	1-hr	DLN, SCR	12/23/2004		RBLC
Calpine Corp. -- Sutter Power Plant	CA	NG	500	2			2 ppm @ 15% O2	1-hr	SCR	08/16/2004		RBLC
Three Mountain Power, LLC	CA	NG		2	2	GE 7FA or SW 501F	2.5 ppm @ 15% O2	1-hr	SCR	10/10/2003		CARB BACT Clearinghouse
Western Midway Sunset Power Project	CA	NG		2		GE 7FA or SW 501F	2 ppm @ 15% O2	1-hr	SCR	12/12/2003		CARB BACT Clearinghouse
Elk Hills Power Project	CA	NG		2		GE 7FA	2.5 ppm @ 15% O2	1-hr	SCR	03/01/2003		CARB BACT Clearinghouse
Magnolia Power Project, SCPPA	CA	NG	181	1		GE 7FA	2 ppm @ 15% O2	1-hr	SCR	5/7/2003		CARB BACT Clearinghouse
Calpine Corp. -- Rocky Mountain Energy Center, LLC	CO	NG	300	1		F-class	3 ppm @ 15% O2	1-hr	DLN, SCR	05/02/2006	NO _x Limited To Max of 100 PPM @ 15% O2 during startup and shutdown.	RBLC
Jacksonville Electric Authority - Brandy Branch (revision)	FL	NG; FO	200	0	2	GE 7FA (170 MW)	3.5 ppm NG; 15 ppm FO	3-hr	SCR	03/29/2002	Conversion of 2 SC units to 2 CC units	EPA Region 4 and 7 CT Spreadsheet
TECO Bayside Power Station (repowering)	FL	NG	1,032	4	0	GE 7FA (170 MW)	3.5 ppm	24-hr	SCR	01/09/2002	Repowering Project: Netting out of PSD for NOx, SO2, lead and SAM (subject for PM10, VOC and CO)	EPA Region 4 and 7 CT Spreadsheet
CPV Cana Power Generation Facility	FL	NG; FO	245	1	1	GE 7FA (170 MW)	2.5 ppm NG; 10 ppm FO	24-hr	SCR	01/17/2002	PA limited to 2,000 hr/yr; CO w/FO: 90-100%/76-89%/50-75% load	EPA Region 4 and 7 CT Spreadsheet
FPC - Hines Energy Complex	FL	NG; FO	530	2	0	SW 501FD (170 MW)	2.5 ppm NG/10 ppm FO	24-hr	SCR	09/19/2003	SCONox - \$8,597/ton NO _x ;	EPA Region 4 and 7 CT Spreadsheet
FPL Turkey Point	FL	NG; FO	1,150	4	4	GE 7FA (170 MW)	2.0 ppm NG/8.0 ppm FO	24-hr	SCR	02/08/2005	SCR (3.5ppm) = \$3,744/ton NO _x ; SCR (2.5 ppm) = \$3,753/ton NO _x	EPA Region 4 and 7 CT Spreadsheet
Progress Energy - Hines Energy Complex (Unit 4)	FL	NG; FO	530	2	0	GE 7FA (170 MW)	2.5 ppm NG/10 ppm FO	24-hr	SCR	06/08/2005		EPA Region 4 and 7 CT Spreadsheet/RBLC
Florida Municipal Power Agency --Treasure Coast Energy Center	FL	NG; FO	300	1		GE 7FA	2.0 ppm NG; 8.0 ppm FO	24-hr block	SCR	05/30/2006	180 km from the Everglades National Park	RBLC
Orlando Utilities Commission -- Curtis H. Stanton Energy Center, Unit B	FL	NG; FO	285	1	1	GE 7FA	2.0 ppm NG; 8.0 ppm FO	24-hr block	SCR	Application under Review		FDEP NSR/PSD Permits
FPL West County Energy Center	FL	NG; FO	2,500	6	6	Mitsubishi M501G	2.0 ppm NG (CT/CT and DB); 8.0 ppm FO	24-hr block	SCR	01/10/2007	SCR - \$3,385/ton NO _x	FDEP NSR/PSD Permits
GenPower Rincon	GA	NG	528	2	2	GE 7FA (170 MW)	2.5 ppm		SCR	03/24/2003		EPA Region 4 and 7 CT Spreadsheet
Savannah Electric and Power - Plant McIntosh	GA	NG; FO	1,260	4	4	GE 7FA (170 MW)	2.5 ppm NG; 6 ppm FO		SCR	04/17/2003	After June 1, 2007 - FO must have < 0.0015%S (ultra low S diesel)	EPA Region 4 and 7 CT Spreadsheet
Live Oak Co., LLC	GA	NG	600	2	2	SW 501FD (170 MW)	3.5 ppm		SCR	02/04/2004		EPA Region 4 and 7 CT Spreadsheet
Big River Power, LLC	GA	NG; FO	855	3	3	GE 7FA (170 MW)	3.0 ppm NG; 8.0 ppm FO		SCR/DLN; WI	applic. under review	SCR - \$5,075/ton NO _x ; CatOx - \$4,712/ton CO	EPA Region 4 and 7 CT Spreadsheet

NO _x Top Down RBLC Clearinghouse Review Results Table A-1												
FACILITY	STATE	FUEL	New (MW)	# of CCCTs	# of DBs	Turbine Model	LIMIT (LB/MBTU)	AVG PERIOD	CONTROL TECHNOLOGY	STATUS	COMMENTS	DATA SOURCE
Hawkeye Generation, LLC (a division of Entergy)	IA	NG	580	2	2	GE 7FA	SC-9 ppm, CC-3 ppm	3-hour	SC-DLN; CC-SCR	07/23/2002	Duct burning limited to 4,500 hours per year	EPA Region 4 and 7 CT Spreadsheet
Interstate Power and Light - Exira Station	IA	NG; FO	568	2	1	2- GE-7FA,1- HRSG w/aux firing @ 405MMBTU	SC-9 ppm (NG), 42 ppm (oil); CC-3 ppm (NG), 33 ppm (oil)	3-hour	SC-DLN, CC-SCR	12/20/2002		EPA Region 4 and 7 CT Spreadsheet
Kentucky Pioneer Energy	KY	syngas/NG	540	2	0	GE 7FA (197 MW)	15/20 ppm	3-hr	Steam Injection	06/08/2001		EPA Region 4 and 7 CT Spreadsheet
Duke Energy Trimble	KY	NG; FO	1,240	4	4	GE 7FA (160 MW)	3.5 ppm		SCR	applic. under review		EPA Region 4 and 7 CT Spreadsheet
Duke Energy (Leavenworth County)	KS	NG	620	2	2	2 - GE-7FA (310 MW each)	4.5 ppm	24-hour	SCR, DLN	02/07/2002		EPA Region 4 and 7 CT Spreadsheet
Crescent City Power, LLC -- Crescent City Power	LA	NG	600	2	2		3 ppm	Annual	DLN, SCR	06/06/2005	Startup emissions is limited to 220 lbs/hr; Project-wide emissions is limited to 74.33 tpy.	RBLC
Crossroads Energy Center	MS	NG	580	2	2	GE 7FA (170 MW)	3.5 ppm		SCR	06/24/2002	SCONox - \$23,400/ton NOx; CatOx - \$11,039/ton CO	EPA Region 4 and 7 CT Spreadsheet
Reliant Energy Choctaw County, LLC	MS	NG	920	3		F-class	3.5 ppm @ 15% O2	3-hr	SCR	11/23/2004	Limits apply at all times.	RBLC
Berrien Energy, LLC	MI	NG	1100	3	3		2.5 ppm @ 15% O2	24-hr	DLN, SCR	04/13/2005	Project-wide emissions is limited to 239.4 tpy.	RBLC
Nebraska Public Power District	NE		220	2		2 on 1 CC with 2 GE 7E CTs	3.5 ppm	3-hr	SCR	05/29/2003		EPA Region 4 and 7 CT Spreadsheet
El Dorado Energy, LLC	NV	NG	475	2	2		3.5 ppm @ 15% O2 (w/o DBs); 3.7 ppm @ 15% O2 (w DBs)		DLN, SCR	08/19/2004		RBLC
Sierra Pacific Power Company -- Tracy Substation Expansion Project	NV	NG	612	2	2		2 ppm @ 15% O2	3-hr	SCR w/Ammonia Inj.	08/16/2005		RBLC
Bessicorp - Empire Development Co., LLC	NJ	NG; FO	1,280	3	3	GE 7FA	2.5 ppm NG; 9 ppm FO	1 hour	DLN/SCR	08/24/2002		EPA Region 4 and 7 CT Spreadsheet
Bessicorp - Empire Development Co., LLC	NY	NG; FO	560	2	2	GE Frame 7FA		1 hour		09/23/2004		EPA Region 4 and 7 CT Spreadsheet
GenPower Earleys, LLC	NC	NG	528	2	2	GE 7FA (170 MW)	2.5/3.5 ppm		SCR	01/14/2002	CO Limit depends on CT model; NOx limit depends on operating history and 3.3 ppm trigger level SCONox - \$21,942/ton NOx; CatOx - \$3,246ton CO	EPA Region 4 and 7 CT Spreadsheet
Mirant Gastonia	NC	NG	1,200	4	4	"F" Class (175 MW)	2.5/3.5 ppm	24-hr block	SCR	05/28/2002	CO Limit depends on CT model; NOx limit depends on operating history and 3.3 ppm trigger level	EPA Region 4 and 7 CT Spreadsheet
Mountain Creek - Granville Energy Center	NC	NG	911	3	3	GE 7FA (170 MW)	3.5 ppm		SCR	applic. under review	SCONox - \$22,600/ton NOx; CatOx - \$3,560ton CO	EPA Region 4 and 7 CT Spreadsheet
Dominion Person, Inc.	NC	NG; FO	1,100	4	4	GE 7FA (172 MW)	3.5 ppm; 15 ppm FO		SCR	applic. under review		EPA Region 4 and 7 CT Spreadsheet
Forsyth Energy Projects, LLC -- Forsyth Energy Plant	NC	NG; FO	812	3	3	GE 7FA (170 MW)	2.5 ppmdv @ 15% O2 (first 500 hours); 3 ppmdv @ 15% O2 (after 500 hours)	24-hr	DLN, SCR	09/29/2005	The use of fuel oil is limited to 1,200 hours per year and only during the months of November through March.	RBLC/EPA Region 4 and 7 CT Spreadsheet
Duke Energy Hanging Rock, LLC -- Duke Energy Hanging Rock Energy Facility	OH	NG	1270	4	4	GE 7FA	3 ppm @ 15% O2	3-hr	DLN, SCR	12/28/2004	The maximum hours of operation of the duct burners shall not exceed 5500 hrs/12-month rolling avg. for each turbine.	RBLC
Port Westward (Portland General Electric)	OR, Permit 05-0008	NG	650	2	2	GE 7FB or SW 501S	2.5 ppmdv @ 15% O2	8-hr	DLN, SCR	01/16/2002	Not yet constructing. Source is expected to submit a request for permit extension given that construction is not expected to commence within 18 months of permit issuance. ODEQ - Northwest Region. Clatskanie, OR. Extension out for public comment.	EPA Region 4 and 7 CT Spreadsheet

NO_x Top Down RBLC Clearinghouse Review Results Table A-1									
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FACILITY	STATE	FUEL	New (MW)	# of CCCTs	# of DBs	Turbine Model	LIMIT (LB/MBTU)	AVG PERIOD	CONTROL TECHNOLOGY	STATUS	COMMENTS	DATA SOURCE
Umatilla Generating (PG&E)	OR, Permit 30-0007	NG	580	2	2	GE 7FB	2.0 ppmdv @ 15% O2	3-hr	DLN, SCR	01/18/2002	Not yet constructing. 05/24/03 permit extension. ODEQ - Eastern Region. Hermiston, OR.	EPA Region 4 and 7 CT Spreadsheet
Turner Energy Center (Calpine)	OR	NG	620	2	2	GE 7FA			DLN, SCR	Public comment period - 7/30/04	Not yet constructing. Not yet permitted. Startup projected 2005. ODEQ - Western Region. Turner, OR.	EPA Region 4 and 7 CT Spreadsheet
California Oregon Border (Peoples Energy)	OR, Permit 18-0029	NG	1,150	4	4	F-class	2.5 ppmdv @ 15% O2	8-hr	DLN, SCR	12/30/2003	Not yet constructing. Not yet permitted. Air-cooled condensor. ODEQ - Eastern Region. Bonanza, OR.	EPA Region 4 and 7 CT Spreadsheet
Klamath Generation LLC (Pacific Power Energy Marketing)	OR, Permit 18-0026	NG	480	2	2	Various	2.5 ppmdv @ 15% O2	8-hr	DLN, SCR	03/14/2003	Constructing? ODEQ - Eastern Region. Klamath Falls, OR.	EPA Region 4 and 7 CT Spreadsheet
WANAPA Energy Center (Diamond Wanapa LLC)	OR, EPA	NG	1,200	4	4	F-class			DLN, SCR	Drafting	Not yet constructing. Not yet permitted. Construction projected to commence Spring '04, startup projected Summer '06. EPA Region 10. Umatilla, OR.	EPA Region 4 and 7 CT Spreadsheet
West Cascades Energy	OR, LRAPA	NG	900	2	2	F-class			DLN, SCR	Drafting	Lane County, OR.	EPA Region 4 and 7 CT Spreadsheet
Diamond Wanapa 1, L.P. -- Wanapa Energy Center	OR	NG	1200	4	4	GE 7FA	2 ppm @ 15% O2	3-hr	DLN, SCR	08/08/2005	The final permit was affirmed by EPA's Environmental Appeals Board on Feb. 9, 2006.	RBLC
Jasper County Generating Facility	SC	NG, FO	1,260	4	4	GE 7FA (170 MW)	2.5 ppm NG; 7.5 ppm FO	24-hr	SCR	05/28/2002	SCONox - \$19,870/ton NOx; CatOx - \$3,320/ton CO	EPA Region 4 and 7 CT Spreadsheet
Fork Shoals Energy, LLC	SC	NG	1,150	2	2	"F" Class (175 MW)	3.5 ppm	24-hr	SCR	applic. under review		EPA Region 4 and 7 CT Spreadsheet
Palmetto Energy Center	SC	NG	970	3	3	GE 7FB (180 MW)	3.5 ppm		SCR	applic. under review	SCONox - \$18,789/ton NOx; CatOx - \$2,111/ton CO	EPA Region 4 and 7 CT Spreadsheet
Haywood Energy Center (Calpine)	TN	NG; FO	900	3	3	SW, GE 7FA or GE F7B	3.5 ppm NG; 42 ppm FO		DLN/SCR; WI	02/01/2002		EPA Region 4 and 7 CT Spreadsheet
Duke Energy	TX		620	2		F7FA	5		SCR	07/23/2003		EPA Region 4 and 7 CT Spreadsheet
TX Petrochem	TX	NG	900	3		GE 7FA	5 ppm		SCR	10/08/2003		EPA Region 4 and 7 CT Spreadsheet
Pacificorp - Currant Creek Power Project	UT	NG	1,050	2	2	GE 7FA	9.0 ppm SC; 2.25 ppm CC; 25 ppm (transient load conditions)	18-HR SC; 3-hr CC; ERR	DLN - SC; SCR - CC	05/17/2004	Project scaled back from 4 turbines to 2 turbines based on impacts to nonattainment area nearby.	EPA Region 4 and 7 CT Spreadsheet
Summit Vineyard -- Lakeside Power Plant	UT	NG	560	2	2	SW 501FD	2 ppm @ 15% O2	3-hr	SCR	01/06/2005		RBLC
Tenaska Fluvanna	VA	NG/FO	900	3	3	GE 7FA	3.0 ppm		SCR	01/20/2002		EPA Region 4 and 7 CT Spreadsheet
CPV Warren	VA	NG	580	2	2	GE 7FA (170 MW)	2.0 ppmdv @ 15% O2	1-hr	DLN, SCR	06/05/2007		RBLC
Duke Energy Wythe, LLC	VA	NG	580	2	2	GE 7FA	2.5 ppm @ 15% O2		DLN, SCR	02/05/2004		RBLC
Frederickson Power II (West Coast Energy)	WA, PSCAA NOC 8695	NG; FO	290	1	0	GE Frame 7FA	2.5 / 6 ppmdv gas / oil @ 15% O2	1-hr	DLN, SCR	06/19/2003	Not built. Permit expires 01/01/05. Minor NSR BACT. PSCAA. Frederickson, WA.	EPA Region 4 and 7 CT Spreadsheet
BP Cherry Point Cogen	WA	NG	720	3	3	GE 7FA	2.5 ppmdv @ 15% O2	Annual	DLN, SCR	Public comment period is over.	Not constructing as permit not yet issued. EFSEC & EPA. Blaine, WA.	EPA Region 4 and 7 CT Spreadsheet
Wallula Power (Newport Northwest Generation)	WA	NG	1,300	4	4	GE 7FA	2.5 ppmdv @ 15% O2	3-hr	DLN, SCR	03/03/2003	Not constructing. Construction on hold due to market conditions. BPA anticipates new generation development within the next five years. EFSEC & EPA. Wallula, WA.	EPA Region 4 and 7 CT Spreadsheet
BP West Coast Products, LLC -- BP Cherry Point Cogeneration Project	WA	NG	720	3	3	GE 7FA	2.5 ppm @ 15% O2	3-hr	DLN, SCR	01/11/2005		RBLC

Color Code Legend

Data from EPA Regions 4 and 7 Combustion Turbine Spreadsheet

Data from EPA's RBLC Clearinghouse

Data from Florida Department of Environmental Protection NSR/PSD Construction Permits Website -- Power Plants

Data from CARB's BACT Clearinghouse

Attachment 2
CO Control Technology Review List

CO Top Down RBLC Clearinghouse Review Results Table A-2												
FACILITY/COMPANY	STATE	FUEL	New (MW)	# of CCCTs	# of DBs	Turbine Model	LIMIT (LB/MBTU)	AVG PERIOD	CONTROL TECHNOLOGY	STATUS	COMMENTS	DATA SOURCE
Barton Shoals Energy, LLC	AL	NG	1,200	4	4	GE 7FA (170 MW)	10 ppm (0.022 lb/mmbtu); 0.041 lb/mmbtu w/DB		GCP	07/15/2002	EPA did not received application until 5/24/02	EPA Region 4 and 7 CT Spreadsheet
Dome Valley Energy Partners -- Wellton Mohawk Generation Station	AZ	NG	310	1	1	GE 7FA	3 ppm @ 15% O2	3-hr	CatOx	12/01/2004		RBLC
Salt River Project -- Santan Generating Plant	AZ	NG	900	3	3	GE 7FA	3 ppm @ 15% O2	3-hr	CatOx	03/07/2003		RBLC
Caithness Blythe II, LLC -- Blythe Energy Project II	CA	NG	580	2	2	GE 7FA (170 MW)	4.0 ppm _{dv} @ 15% O2	3-hr		04/25/2007		RBLC
Calpine Corp. -- Sutter Power Plant	CA	NG	500	2			4 ppm @ 15% O2	3-hr	CatOx	08/16/2004		RBLC
Three Mountain Power, LLC	CA	NG		2	2	GE 7FA or SW 501F	4 ppm @ 15% O2	3-hr	CatOx	10/10/2003		CARB BACT Clearinghouse
Western Midway Sunset Power Project	CA	NG		2		GE 7FA or SW 501F	4 ppm @ 15% O2	3-hr	CatOx	12/12/2003		CARB BACT Clearinghouse
Elk Hills Power Project	CA	NG		2		GE 7FA	4 ppm @ 15% O2	3-hr	CatOx	03/01/2003	CO limit was offered by catalyst vendor.	CARB BACT Clearinghouse
Magnolia Power Project, SCPPA	CA	NG	181	1		GE 7FA	2 ppm @ 15% O2	1-hr	CatOx	5/7/2003	CO limit was proposed by the applicant.	CARB BACT Clearinghouse
Calpine Corp. -- Rocky Mountain Energy Center, LLC	CO	NG	300	1		F-class	3 ppm @ 15% O2		GCP, CatOx	05/02/2006		RBLC
Jacksonville Electric Authority - Brandy Branch (revision)	FL	NG; FO	200	0	2	GE 7FA (170 MW)	14 ppm	24-hr	GCP	03/29/2002	Conversion of 2 SC units to 2 CC units	EPA Region 4 and 7 CT Spreadsheet
TECO Bayside Power Station (repowering)	FL	NG	1,032	4	0	GE 7FA (170 MW)	9 ppm (7.8 ppm test avg.)	24-hr	GCP	01/09/2002	Repowering Project: Netting out of PSD for NOx, SO2, lead and SAM (subject for PM10, VOC and CO)	EPA Region 4 and 7 CT Spreadsheet
CPV Cana Power Generation Facility	FL	NG; FO	245	1	1	GE 7FA (170 MW)	8 ppm NG (13 ppm w/PA) ; 17/19/26 ppm FO	24-hr	GCP	01/17/2002	PA limited to 2,000 hr/yr; CO w/FO: 90-100%/76-89%/50-75% load	EPA Region 4 and 7 CT Spreadsheet
FPC - Hines Energy Complex	FL	NG; FO	530	2	0	SW 501FD (170 MW)	10 ppm NG/20 ppm FO	24-hr	GCP	09/19/2003	SCONox - \$8,597/ton NOx;	EPA Region 4 and 7 CT Spreadsheet
FPL Turkey Point	FL	NG; FO	1,150	4	4	GE 7FA (170 MW)	4.1 ppm NG/7.6 ppm NG w/DB/8 ppm NG w/PA&DB/14ppm w/PK&DB; 8.0 ppm FO/ & 6.0 ppm (12-month avg.)All modes	24-hr/12-mo	GCP	02/08/2005	SCR (3.5ppm) = \$3,744/ton NOx; SCR (2.5 ppm) = \$3,753/ton NOx	EPA Region 4 and 7 CT Spreadsheet
Progress Energy - Hines Energy Complex (Unit 4)	FL	NG; FO	530	2	0	GE 7FA (170 MW)	8 ppm @ 15% O2 NG; 12 ppm FO	24-hr	GCP	06/08/2005		EPA Region 4 and 7 CT Spreadsheet/RBLC
Florida Municipal Power Agency --Treasure Coast Energy Center	FL	NG; FO	300	1		GE 7FA	6 ppm (12-month); 8 ppm FO (24-hr); 4.1 ppm NG w/o DBs (24-hr)	12-month or 24-hr	GCP	05/30/2006	Continuous compliance with ppm limit by CEMS	RBLC
Progress Energy -- P.L. Bartow Power Plant	FL	NG; FO	1,475	4	4	Siemens SGT6-5000F	FO: 8.0 ppm @ 15% O2 (CT); NG: 4.1 ppm @ 15% O2 (CT) and 7.6 ppm @ 15% O2 (CT + DB)	3-hr Stack Test	GCP	Draft Permit	CEMS Block Average for CO -- 8.0 ppm @ 15% O2 (24-hr avg.) / 6.0 ppm @ 15% O2 (12-month rolling avg.); Cat. Ox. -- \$3,956/ton CO	FDEP NSR/PSD Permits
Orlando Utilities Commission -- Curtis H. Stanton Energy Center, Unit B	FL	NG; Syn. Gas	285	1	1	GE 7FA	Syn. Gas or NG: 4.1 ppm @ 15% O2 (between 21 and 27 months following the initial compliance tests)	24-hr rolling avg.	CatOx	12/22/2006		FDEP NSR/PSD Permits
FPL West County Energy Center	FL	NG; FO	2,500	6	6	Mitsubishi M501G	FO: 8.0 ppm @ 15% O2 (CT); NG: 4.1 ppm @ 15% O2 (CT) and 7.6 ppm @ 15% O2 (CT + DB)	3-hr Stack Test	GCP	01/10/2007	CEMS Block Average for CO -- 8.0 ppm @ 15% O2 (24-hr avg.) / 6.0 ppm @ 15% O2 (12-month rolling avg.)	FDEP NSR/PSD Permits
GenPower Rincon	GA	NG	528	2	2	GE 7FA (170 MW)	2.0 ppm		CatOx	03/24/2003		EPA Region 4 and 7 CT Spreadsheet
Savannah Electric and Power - Plant McIntosh	GA	NG; FO	1,260	4	4	GE 7FA (170 MW)	2.0 ppm		CatOx	04/17/2003	After June 1, 2007 - FO must have < 0.0015%S (ultra low S diesel)	EPA Region 4 and 7 CT Spreadsheet
Live Oak Co., LLC	GA	NG	600	2	2	SW 501FD (170 MW)	10 ppm (17 ppm w/DB or PA)		GCP	02/04/2004		EPA Region 4 and 7 CT Spreadsheet
Big River Power, LLC	GA	NG; FO	855	3	3	GE 7FA (170 MW)	19.2 ppm (w/DB)/9.0 ppm (w/o DB) NG; 20.0 ppm FO		GCP	applic. under review	SCR - \$5,075/ton NOx; CatOx - \$4,712/ton CO	EPA Region 4 and 7 CT Spreadsheet

CO Top Down RBLC Clearinghouse Review Results Table A-2												
FACILITY	STATE	FUEL	New (MW)	# of CCCTs	# of DBs	Turbine Model	LIMIT (LB/MBTU)	AVG PERIOD	CONTROL TECHNOLOGY	STATUS	COMMENTS	DATA SOURCE
Hawkeye Generation, LLC (a division of Entergy)	IA	NG	580	2	2	GE 7FA	SC-9 ppm, CC-5 ppm	3-hour	Oxidation Catalyst	07/23/2002	Duct burning limited to 4,500 hours per year	EPA Region 4 and 7 CT Spreadsheet
Interstate Power and Light - Exira Station	IA	NG; FO	568	2	1	2- GE-7FA,1- HRSG w/aux firing @ 405MMBTU	SC-9 ppm (NG), 20 ppm (oil); CC-5 ppm (NG), 7.1 ppm (oil)	3-hour	Oxidation Catalyst	12/20/2002		EPA Region 4 and 7 CT Spreadsheet
Kentucky Pioneer Energy	KY	syngas/NG	540	2	0	GE 7FA (197 MW)	15/20 ppm	3-hr	GCP	06/08/2001		EPA Region 4 and 7 CT Spreadsheet
Duke Energy Trimble	KY	NG; FO	1,240	4	4	GE 7FA (160 MW)	9/13.9/20 ppm		GCP	applic. under review		EPA Region 4 and 7 CT Spreadsheet
Duke Energy (Leavenworth County)	KS	NG	620	2	2	2 - GE-7FA (310 MW each)	16.9 ppm	short-term	GCP	02/07/2002		EPA Region 4 and 7 CT Spreadsheet
Crescent City Power, LLC -- Crescent City Power	LA	NG	600	2	2		4 ppm @ 15% O2	Annual	GCP, CatOx	06/06/2005	Startup emissions is limited to 1,530 lbs/hr; Project-wide emissions is limited to 567.11 tpy.	RBLC
Nothernern States Power Co. DBA XCEL Energy -- Riverside Plant	MN	NG	528	2	0	GE 7FA (170 MW)	10.0 ppmdv @ 15% O2	3-hr	GCP	05/16/2006	Three existing coal-fired boilers being replaced by 2 GE 7FA CCCTs; CatOx rejected at \$7,670/ton of CO	RBLC
Crossroads Energy Center	MS	NG	580	2	2	GE 7FA (170 MW)	10.4 ppm		GCP	06/24/2002	SCONox - \$23,400/ton NOx; CatOx - \$11,039/ton CO	EPA Region 4 and 7 CT Spreadsheet
Reliant Energy Choctaw County, LLC	MS	NG	920	3		F-class	18.36 ppmv @ 15% O2	3-hr	GCP	11/23/2004		RBLC
Berrien Energy, LLC	MI	NG	1100	3	3		2 ppm @ 15% O2	3-hr	CatOx	04/13/2005	All 3 turbines and duct burners combined are limited to 165.5 tpy	RBLC
Nebraska Public Power District	NE		220	2		2 on 1 CC with 2 GE 7E CTs	10.8 lb/hr	Stack	CatOx	05/29/2003		EPA Region 4 and 7 CT Spreadsheet
Sierra Pacific Power Company -- Tracy Substation Expansion Project	NV	NG	612	2	2		0.03 lb/Mbtu	3-hr	GCP	08/16/2005		RBLC
El Dorado Energy, LLC	NV	NG	475	2	2		2.6 ppm @ 15% O2 (each CTG); 3.5 ppm @ 15% O2 (CTG + DB)		CatOx	08/19/2004		RBLC
Bessicorp - Empire Development Co., LLC	NJ	NG; FO	1,280	3	3	GE 7FA	4 ppm	1 hour	CatOx	08/24/2002		EPA Region 4 and 7 CT Spreadsheet
Bessicorp - Empire Development Co., LLC	NY	NG; FO	560	2	2	GE Frame 7FA				09/23/2004		EPA Region 4 and 7 CT Spreadsheet
GenPower Earleys, LLC	NC	NG	528	2	2	GE 7FA (170 MW)	9 ppm (14 ppm w/DB)		GCP	01/14/2002	CO Limit depends on CT model; NOx limit depends on operating history and 3.3 ppm trigger level SCONox - \$21,942/ton NOx; CatOx - \$3,246ton CO	EPA Region 4 and 7 CT Spreadsheet
Mirant Gastonia	NC	NG	1,200	4	4	"F" Class (175 MW)	15 or 30 ppm	24-hr block	GCP	05/28/2002	CO Limit depends on CT model; NOx limit depends on operating history and 3.3 ppm trigger level	EPA Region 4 and 7 CT Spreadsheet
Mountain Creek - Granville Energy Center	NC	NG	911	3	3	GE 7FA (170 MW)	9 ppm (24.3 ppm w/DB)		GCP	applic. under review	SCONox - \$22,600/ton NOx; CatOx - \$3,560ton CO	EPA Region 4 and 7 CT Spreadsheet
Dominion Person, Inc.	NC	NG; FO	1,100	4	4	GE 7FA (172 MW)	9 ppm NG (20 ppm w/DB) 20 ppm FO		GCP	applic. under review		EPA Region 4 and 7 CT Spreadsheet
Forsyth Energy Projects, LLC -- Forsyth Energy Plant	NC	NG; FO	812	3	3	GE 7FA (170 MW)	11.6 ppm NG (25.9 ppm w/DB); 15.7 ppm FO (25.1 ppm w/DB)	3-hr	GCP	01/23/2004	CO Limit depends on CT model; NOx limit depends on operating history and 3.3/17 ppm trigger levels	EPA Region 4 and 7 CT Spreadsheet
Duke Energy Hanging Rock, LLC -- Duke Energy Hanging Rock Energy Facility	OH	NG	1270	4	4	GE 7FA	9 ppm @ 15% O2	24-hr	GCP	12/28/2004	The maximum hours of operation of the duct burners shall not exceed 5500 hrs/12-month rolling avg. for each turbine. Each turbine has a limit of 278 tpy of CO.	RBLC
Port Westward (Portland General Electric)	OR, Permit 05-0008	NG	650	2	2	GE 7FB or SW 501S	4.9 ppmdv @ 15% O2	8-hr	CatOx	01/16/2002	Not yet constructing. Source is expected to submit a request for permit extension given that construction is not expected to commence within 18 months of permit issuance. ODEQ - Northwest Region. Clatskanie, OR. Extension out for public comment.	EPA Region 4 and 7 CT Spreadsheet

CO Top Down RBLC Clearinghouse Review Results												
Table A-2												
FACILITY	STATE	FUEL	New (MW)	# of CCCTs	# of DBs	Turbine Model	LIMIT (LB/MBTU)	AVG PERIOD	CONTROL TECHNOLOGY	STATUS	COMMENTS	DATA SOURCE
Umatilla Generating (PG&E)	OR, Permit 30-0007	NG	580	2	2	GE 7FB	6.0 ppmdv @ 15% O2	24-hr	CatOx	01/18/2002	Not yet constructing. 05/24/03 permit extension. ODEQ - Eastern Region. Hermiston, OR.	EPA Region 4 and 7 CT Spreadsheet
Turner Energy Center (Calpine)	OR	NG	620	2	2	GE 7FA			CatOx	Public comment period - 7/30/04	Not yet constructing. Not yet permitted. Startup projected 2005. ODEQ - Western Region. Turner, OR.	EPA Region 4 and 7 CT Spreadsheet
California Oregon Border (Peoples Energy)	OR, Permit 18-0029	NG	1,150	4	4	F-class	5.0 ppmdv @ 15% O2	8-hr	CatOx	12/30/2003	Not yet constructing. Not yet permitted. Air-cooled condensor. ODEQ - Eastern Region. Bonanza, OR.	EPA Region 4 and 7 CT Spreadsheet
Klamath Generation LLC (Pacific Power Energy Marketing)	OR, Permit 18-0026	NG	480	2	2	Various	5.0 ppmdv @ 15% O2	8-hr	CatOx	03/14/2003	Constructing? ODEQ - Eastern Region. Klamath Falls, OR.	EPA Region 4 and 7 CT Spreadsheet
WANAPA Energy Center (Diamond Wanapa LLC)	OR, EPA	NG	1,200	4	4	F-class			CatOx	Drafting	Not yet constructing. Not yet permitted. Construction projected to commence Spring '04, startup projected Summer '06. EPA Region 10. Umatilla, OR.	EPA Region 4 and 7 CT Spreadsheet
West Cascades Energy	OR, LRAPA	NG	900	2	2	F-class				Drafting	Lane County, OR.	EPA Region 4 and 7 CT Spreadsheet
Diamond Wanapa 1, L.P. -- Wanapa Energy Center	OR	NG	1200	4	4	GE 7FA	2 ppm @ 15% O2	3-hr	CatOx	08/08/2005	The final permit was affirmed by EPA's Environmental Appeals Board on Feb. 9, 2006.	RBLC
Jasper County Generating Facility	SC	NG, FO	1,260	4	4	GE 7FA (170 MW)	9 ppm NG (14 ppm w/DB); 20 ppm FO (22 ppm w/DB)		GCP	05/28/2002	SCONox - \$19,870/ton NOx; CatOx - \$3,320/ton CO	EPA Region 4 and 7 CT Spreadsheet
Fork Shoals Energy, LLC	SC	NG	1,150	2	2	"F" Class (175 MW)	14 ppm (GE7FA/16 ppm (SW501F)	24-hr	GCP	applic. under review		EPA Region 4 and 7 CT Spreadsheet
Palmetto Energy Center	SC	NG	970	3	3	GE 7FB (180 MW)	15 ppm (31 ppm w/DB)		GCP	applic. under review	SCONox - \$18,789/ton NOx; CatOx - \$2,111/ton CO	EPA Region 4 and 7 CT Spreadsheet
Haywood Energy Center (Calpine)	TN	NG; FO	900	3	3	SW, GE 7FA or GE 7FB	varies from 7.4 to 50 ppm depending on CT type and load		GCP	02/01/2002		EPA Region 4 and 7 CT Spreadsheet
TX Petrochem	TX	NG	900	3		GE 7FA	15 ppm		GCP	10/08/2003		EPA Region 4 and 7 CT Spreadsheet
Duke Energy	TX		620	2		F7FA	20			07/23/2003		EPA Region 4 and 7 CT Spreadsheet
Pacificorp - Currant Creek Power Project	UT	NG	1,050	2	2	GE 7FA	7.8 ppm SC; 3.0 ppm CC	24-HR SC; 3-hr CC; ERR	Oxid Cat	05/17/2004	Project scaled back from 4 turbines to 2 turbines based on impacts to nonattainment area nearby.	EPA Region 4 and 7 CT Spreadsheet
Summit Vineyard -- Lakeside Power Plant	UT	NG	560	2	2	SW 501FD	3 ppm @ 15% O2	3-hr	CatOx	01/06/2005		RBLC
Tenaska Fluvanna	VA	NG/FO	900	3	3	GE 7FA	21 ppm		GCP	01/20/2002		EPA Region 4 and 7 CT Spreadsheet
Duke Energy Wythe, LLC	VA	NG	580	2	2	GE 7FA	9 ppm @ 15% O2		DLN, SCR	02/05/2004		RBLC
CPV Warren	VA	NG	580	2	2	GE 7FA (170 MW)	2.5 ppmdv @ 15% O2 with Power Augmentation and DBs		CatOx and GCP	06/05/2007	CO Limit: 1.3 ppmvd @15% O2 w/o Power Aug., 1.8 ppmvd @ 15% O2 w/Power Aug. and w/o DBs	RBLC
Frederickson Power II (West Coast Energy)	WA, PSCAA NOC 8695	NG; FO	290	1	0	GE Frame 7FA	2.0 / 3.0 ppmdv @ 15% O2	1-hr	CatOx	06/19/2003	Not built. Permit expires 01/01/05. Minor NSR BACT. PSCAA. Frederickson, WA.	EPA Region 4 and 7 CT Spreadsheet
BP Cherry Point Cogen	WA	NG	720	3	3	GE 7FA	2.0 ppmdv @ 15% O2	Ann.	CatOx	Public comment period is over.	Not constructing as permit not yet issued. EFSEC & EPA. Blaine, WA.	EPA Region 4 and 7 CT Spreadsheet
Wallula Power (Newport Northwest Generation)	WA	NG	1,300	4	4	GE 7FA	2.0 ppmdv @ 15% O2	3-hr	CatOx	03/03/2003	Not constructing. Construction on hold due to market conditions. BPA anticipates new generation development within the next five years. EFSEC & EPA. Wallula, WA.	EPA Region 4 and 7 CT Spreadsheet
BP West Coast Products, LLC -- BP Cherry Point Cogeneration Project	WA	NG	720	3	3	GE 7FA	2 ppm @ 15% O2	3-hr	GCP, CatOx	01/11/2005		RBLC
Color Code Legend												
Data from EPA Regions 4 and 7 Combustion Turbine Spreadsheet												
Data from EPA's RBLC Clearinghouse												
Data from Florida Department of Environmental Protection NSR/PSD Construction Permits Website -- Power Plants												
Data from CARB's BACT Clearinghouse												

Appendix E
Air Dispersion Modeling Protocol

Cane Island Power Park Unit 4 Combustion Turbine

Class I and II Air Dispersion Modeling Protocol

January 2008

**Prepared for:
Florida Municipal Power Agency
Orlando, Florida**



Florida Municipal Power Agency
Community Power. Statewide Strength.

**Prepared by:
Black & Veatch
Overland Park, Kansas**



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1.0 Introduction

Florida Municipal Power Agency (FMPA) is proposing to construct and operate a new natural gas-fired combined cycle combustion turbine (CCCT) at their existing Cane Island Power Park (CIPP). This combustion turbine will be Unit 4 at the facility (hereinafter referred to as the Project).

FMPA anticipates that the potential emissions of the Project will trigger air permitting review requirements under the Prevention of Significant Deterioration (PSD) program of Florida Regulation 62-212.400. 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 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. The construction permit application and supporting ambient air quality impact analysis (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, as well as an overview of the local air quality status and NSR and NSPS applicability.

2.1 Project Location

The CIPP is located near Intercession City in Osceola County. 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

FMPA is proposing the installation of a new natural gas-fired, 1 x 1 combined cycle combustion turbine (Unit 4) at their existing CIPP near Intercession City, Florida. Unit 4 will have a nominal rating of 300 megawatts (MW) and will include a GE 7FA combustion turbine generator (CTG), a duct-fired heat recovery steam generator (HRSG), a steam turbine generator (STG), and will be equipped with an evaporative cooler. New major support facilities include a diesel engine driven fire pump, a safe shutdown generator, and a mechanical draft cooling tower.

2.3 Project Emissions

For the proposed Unit 4 CCCT, emissions and stack parameters will be developed from performance data for unit loads of 100, 75, 50, and 40 percent of maximum capacity over a range of representative ambient temperatures (19, 59, 73, and 102°F) for natural gas firing. This range of temperatures represents the site minimum, ISO, site average, and site maximum temperatures. The emissions included in the air dispersion modeling analysis for Unit 4 will be based on direct pound per hour emissions to the atmosphere.

Unit 4 will have the capability of operating in several configurations; including evaporative cooling and duct firing, 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.

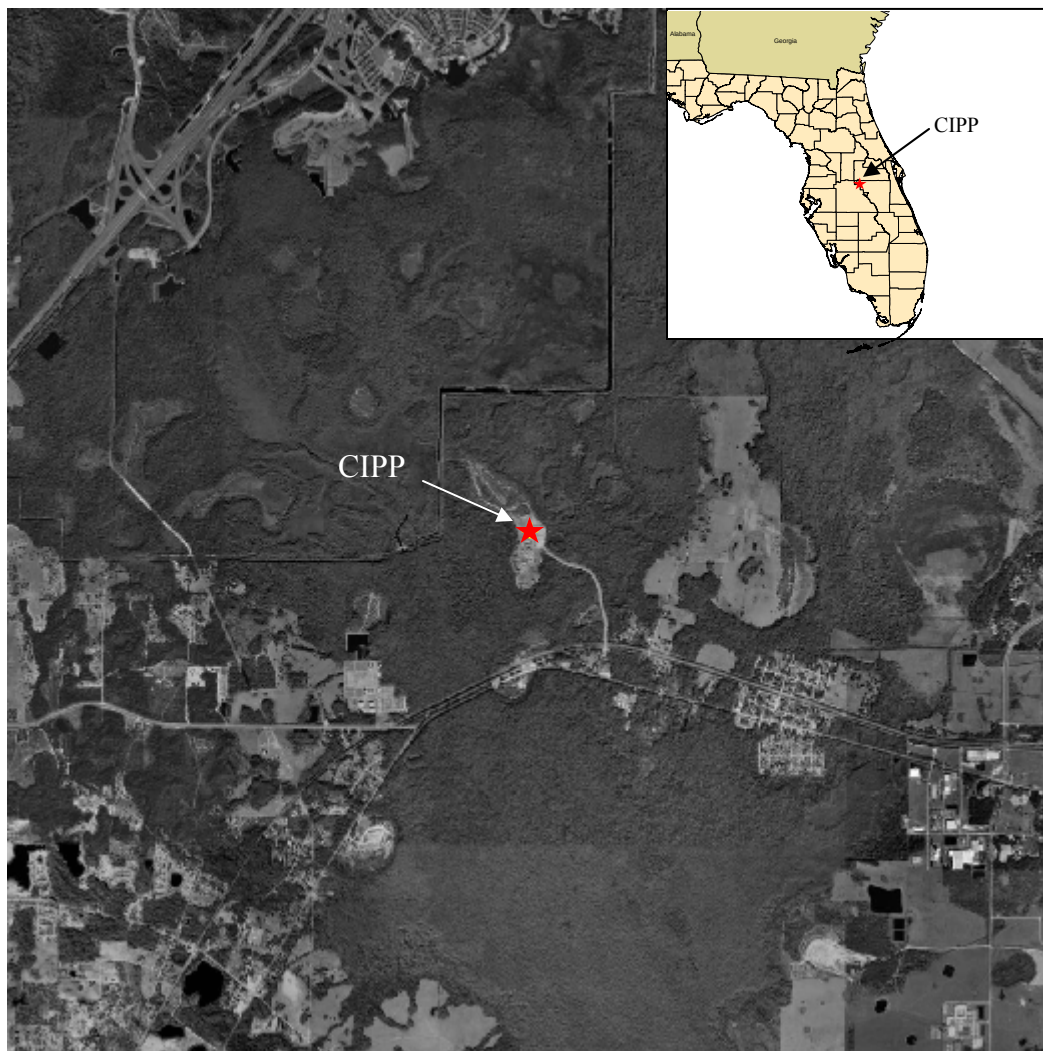


Figure 2-1
Proposed Project Location

The emissions and stack parameters for each of the ancillary equipment will be based on manufacturer data and these emission sources will only be included in the Class II AAQIA.

2.4 Local Air Quality Attainment/Nonattainment Status

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 National Ambient Air Quality Standards (NAAQS). 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 NAAQS. A review of the air quality status in the region reveals that Osceola County is in attainment or unclassifiable for all pollutants.

2.5 New Source Review/PSD Applicability

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. As noted in Section 2.4, the proposed Project is located in an attainment or unclassifiable area with respect to all pollutants. As such, the PSD program, as administered by the state of Florida under 62-212.400, F.A.C., will apply to the proposed project.

The PSD regulations are designed to ensure that the air quality in existing attainment areas does not significantly deteriorate or exceed the NAAQS 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 carefully reviewed prior to construction to ensure compliance with the NAAQS, the applicable PSD air quality increments, and the requirements to apply Best Available Control Technology (BACT) to minimize the emissions of air pollutants.

A major stationary source is defined as any one of the listed major source categories which emits, or has the potential to emit (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. The CIPP is one of the 28 major source categories (i.e., fossil fuel fired steam electric plant) which has a PTE greater than 100 tpy for at least one regulated pollutant; therefore, it is considered an existing major PSD source.

Because the proposed Project is locating at an existing major stationary source, PSD applicability is determined on a pollutant by pollutant basis by comparing the emissions increase of each pollutant against the PSD significant emission rates (SERs).

PSD SERs

- Nitrogen Oxides (NO_x)--40 tpy.
- Sulfur Dioxide (SO₂)--40 tpy.
- Particulate Matter (PM)--25 tpy.
- Particulate Matter less than 10 microns (PM₁₀)--15 tpy.
- Carbon Monoxide (CO)--100 tpy.
- Ozone (O₃)--NO_x or Volatile Organic Compounds (VOC)--40 tpy.
- Lead (Pb)--0.6 tpy.
- Mercury (Hg)--0.1 tpy.
- Fluorides (F)--3 tpy.
- Sulfuric Acid Mist (H₂SO₄)--7 tpy.
- Hydrogen Sulfide (H₂S)--10 tpy.
- Total Reduced Sulfur Compounds--10 tpy.

The project emissions increase and the project net emissions increase must be above the PSD SER for PSD to apply to the project. This is determined on a pollutant by pollutant basis. It is expected that the emissions of NO_x, PM/PM₁₀, SO₂, CO, and sulfuric acid mist will exceed the PSD SER threshold for the proposed Project; therefore, the Project will be required to perform a BACT analysis along with an AAQIA.

2.6 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. The applicable category for the proposed project falls under Subpart KKKK of 40 CFR 60. Specifically, this category is the NSPS for stationary combustion turbines. The criteria for this NSPS will be met or exceeded by the proposed project.

3.0 Class I Ambient Air Quality Analysis

As part of the air impact evaluation for the addition to the CIPP site, analyses of the proposed project's effect on all Class I areas within 200 km will be performed. The Chassahowitzka (CW) Wilderness area is the only Class I area of concern for this project. The CW is a PSD Class I area located in Florida approximately 113 km northwest of the proposed project site. 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 area.

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 CW.

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 area. 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.

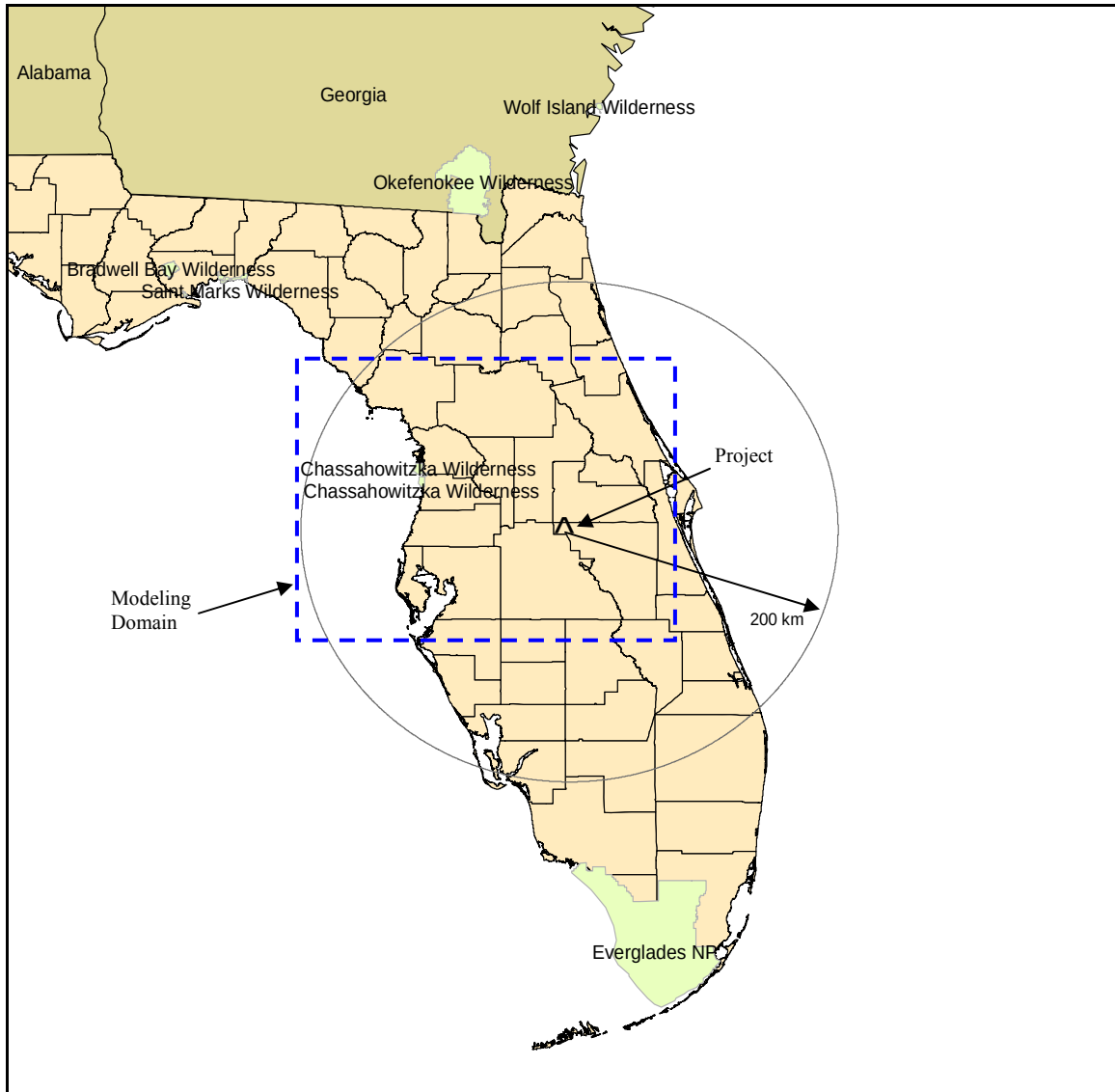


Figure 3-1
Proposed Project Location and Class I Areas

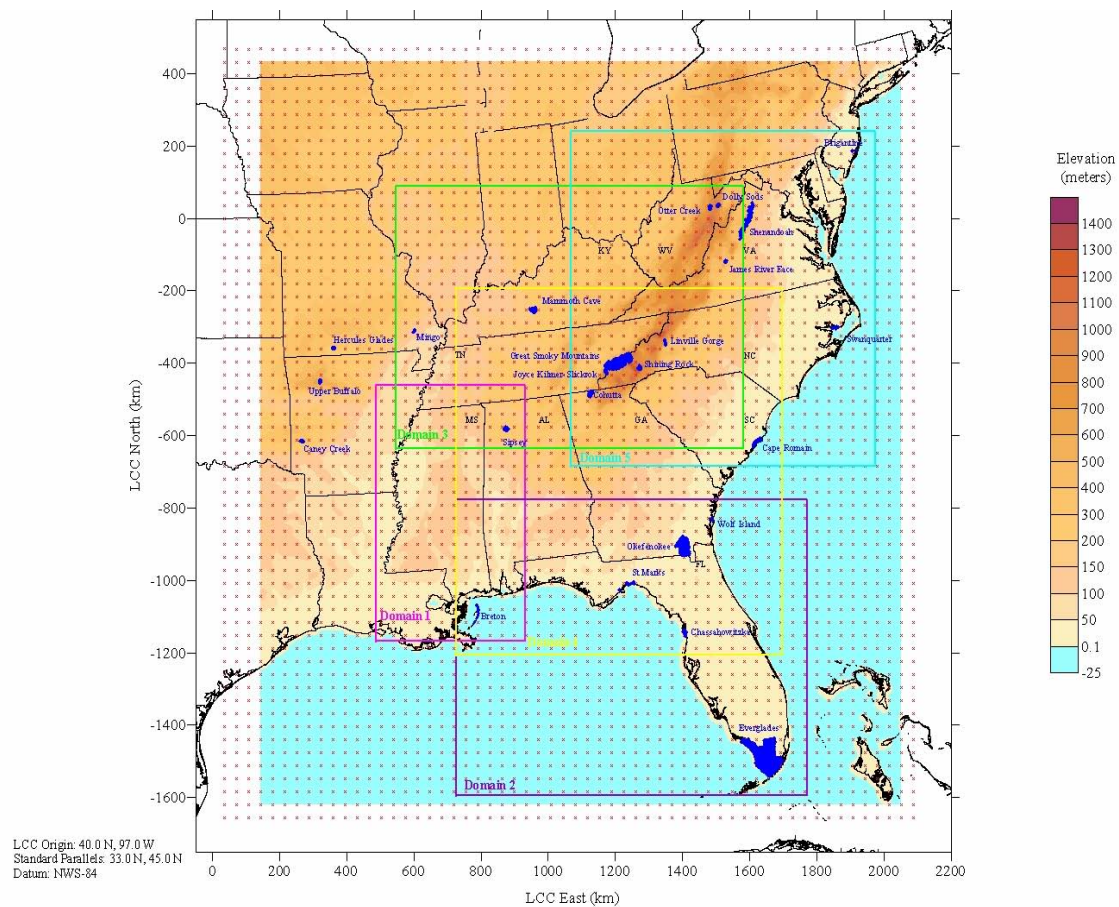


Figure 3-2
VISTAS 4-km CALMET Sub-Domains

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 Unit 4. 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/PM₁₀ emissions will be speciated based on size and composition and therefore be broken into the following constituents: elemental carbon (EC), organic carbon (OC), and soot (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 area, 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 area. Receptor elevations are included in the same NPS- provided receptor 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.

**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	<u>Regional Haze:</u> Highest predicted 24-hour change as processed by CALPOST <u>Class I SILS:</u> 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.

3.1.6.1 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, surface and upper air 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: MM5 data was used for initial guess field, in addition hourly surface data, twice daily upper air soundings, precipitation data, and over water data was used.
- Diagnostic options: IWAQM default values, except as follows: diagnostic terrain blocking and slope flow algorithms used for 2003 simulations (using 36 km MM5 data), but no diagnostic terrain adjustments in 2001 and 2002 simulation (using 12 km MM5 data).
- CALMET options dealing with radius of influence parameters (R1, R2, RMAX1, RMAX2, RMAX3), BIAS, ICALM parameters were predetermined by Earth Tech for each sub-domain.
- TERRAD (terrain scale) is required for runs with diagnostic terrain adjustments (i.e., the 2003 simulations).
- 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) was determined by Earth Tech for the regional simulations based on sensitivity tests.
- Geophysical data for regional runs: USGS 3-arcsec terrain data, Composite Theme Grid (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 area with at least a 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 292 km in the east-west (x) direction and 204 km in the north-south (y) direction will be used for the refined modeling analysis. The southwest corner of the domain is located at 1,317.995 km Easting and -1,254 km Northing (LCC, World Geodetic System (WGS) 1984 coordinates). The grid resolution for the domain will be 4 km. A grid spacing of 4 km yields 73 grid cells in the x-direction and 51 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 area, including regional haze and Class I SILs.

3.2.1 Regional Haze Analysis

A regional haze analysis will be performed for the Class I area, for ammonium sulfates, ammonium nitrates, and particulate matter, by appropriately characterizing model predicted outputs of SO₄, NO₃, and PM₁₀ concentrations. PM₁₀ 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 the Class I areas. 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 area 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:

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

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:

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

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:

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

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 area. The background visual range, or constituents thereof, for the Class I area 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	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; 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 <i>IWAQM Phase II Summary Report and Recommendations for Modeling Long Range Transport Impacts</i> (EPA, 12/98)	

Calculation

Refined impacts will be calculated as follows:

1. Obtain 24-hour SO₄, NO₃, and PM speciation (EC & OC) impacts, in units of micrograms per cubic meter (μg/m³).
2. Convert the SO₄ impact to (NH₄)₂SO₄ by the following formula:

$$(NH_4)_2SO_4 (\mu g/m^3) = SO_4 (\mu g/m^3) \times \text{molecular weight } (NH_4)_2SO_4 / \text{molecular weight } SO_4$$

$$(NH_4)_2SO_4 (\mu g/m^3) = SO_4 (\mu g/m^3) \times 132/96 = SO_4 (\mu g/m^3) \times 1.375$$
3. Convert the NO₃ impact to NH₄NO₃ by the following formula:

$$NH_4NO_3 (\mu g/m^3) = NO_3 (\mu g/m^3) \times \text{molecular weight } NH_4NO_3 / \text{molecular weight } NO_3$$

$$NH_4NO_3 (\mu g/m^3) = NO_3 (\mu g/m^3) \times 80/62 = NO_3 (\mu g/m^3) \times 1.29$$
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:

$$b_{extb} = 3.912 / \text{visual range (km)}$$
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 SO₄, NO₃, 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 CW 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 SO₂, SO₄, NO_x, NO₃, and HNO₃ 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 SO₂ and SO₄ contribute sulfur mass and SO₄, NO_x, HNO₃, and NO₃ 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 µg/m³) to the Class I area 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 Orlando surface data and upper air data from Tampa/Ruskin for the data period of 1999-2003. 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/PM₁₀, NO_x, SO₂, and CO.
- Source Modeling Parameters:** Representative combustion turbine performance and emissions data for the several operating configurations; including natural gas firing, evaporative cooling, and duct firing. The performance and emission data will be determined across 40, 50, 75, and 100 percent load cases at ambient temperatures of 19, 59, 73, and 100 °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 and VOC and NO_x emissions will each be less than 100 tpy, 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.
- 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
Electronic Modeling Files