Davin R.

AIR CONSTRUCTION PERMIT APPLICATION FOR THE FLORIDA POWER & LIGHT COMPANY FORT MYERS COMBUSTION TURBINE PROJECT LEE COUNTY, FLORIDA

Module AC020

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JUL 3 1 2013

RESOURCE MANAGEMENT

Project 0710002-019-AC

PSD 424.

Report

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DIVISION OF AIR
RESOURCE MANAGEMENT

July 30, 2013

Jeffery Koerner, P.E., Program Administrator
Office of Permitting and Compliance
Division of Air resource Management
Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399

Project 0710002-019-AC-PSD 424

Re: FPL Lauderdale and Fort Myers Combustion Turbine (CT) Projects
Air Construction Permit Application

Dear Mr. Koerner:

Please find enclosed the Air Construction Permit Applications prepared by Golder Associates for Florida Power & Light Company's (FPL) Lauderdale and Fort Myers CT Projects located in Broward and Lee Counties, respectively. As discussed in FPL's June 3, 2013 letter from Randall LaBauve to Brian Accardo, the enclosed Applications are being filed as part of a plan for Fort Myers, Lauderdale, and Port Everglades Plants to bring off-site concentrations below the new 1-hour NO_2 National Ambient Air Quality Standard (NAAQS). The air quality analyses contained in the Applications demonstrate that retiring 48 existing gas turbines at the Fort Myers, Lauderdale, and Port Everglades Plants and replacing this first-generation combustion technology with new, highly efficient combustion turbines at the Lauderdale and Fort Myers Plants will demonstrate compliance with the 1-hour NO_2 NAAQS. For GHG emissions, FPL will separately file at a later date a Prevention of Significant Deterioration (PSD) application for each Project with the U.S. Environmental Protection Agency (EPA) Region IV, as instructed on the Department's website.

If you have any comments or questions regarding the attached Applications, please feel free to contact me at (561) 691-2808 or Ken Proctor at (561) 691-7068.

Sincerely,
Florida Power & Light Company

Matthew J. Raffenberg
Director of Environmental Licensing and Permitting
Environmental Services Department

cc: Brian Accardo, FDEP
Randall LaBauve, FPL
Ken Kosky, Golder Associates
Peter Cocotos, Esq., FPL

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List of Acronyms

°C	degrees Celsius
°F	degrees Fahrenheit
$\mu g/m^3$	micrograms per cubic meter
AAQS	Ambient Air Quality Standards
AERMOD	American Meteorological Society and U.S. Environmental Protection Agency Regulatory Model
AOR	Annual Operating Report
AQRV	air quality related value
BACT	Best Available Control Technology
BPIP	Building Profile Impact Program
Btu/lb	British thermal unit per pound
Btu/kWh	British thermal unit per kilowatt hour
Btu/scf	British thermal unit per standard cubic foot
CAA	Clean Air Act
CEM	continuous emissions monitoring
cf/yr	cubic foot per year
CFR	Code of Federal Regulations
CH_4	methane
CO	carbon monoxide
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
CT	combustion turbine
DLE	dry low emissions
ENP	Everglades National Park
EPA	U.S. Environmental Protection Agency
F.A.C.	Florida Administrative Code
FDEP	Florida Department of Environmental Protection
FGT	Florida Gas Transmission Company, LLC
FIU	Florida International University
FPL	Florida Power & Light
ft	foot
FR	Federal Register
FFFSGU	fossil fuel fired steam generating unit
g/bhp-hr	grams per brake horsepower-hour
g/s	grams per second
GEP	Good Engineering Practice
gr/100 scf	grains per 100 standard cubic feet
GT	Gas Turbines, (typically referred to the older existing machines on the Project Site)
GHG	greenhouse gas
HAP	hazardous air pollutant

HFCs	hydrofluorocarbons
HHV	higher heating value
hp	horsepower
hr/yr	hours per year
HRSG	heat recovery steam generator
HSH	highest, second highest
Hz	hertz
I	Interstate highway
ICW	Intracoastal Waterway
km	kilometer
kW	kilowatt
lb/hr	pound per hour
lb/MMBtu	pound per million British thermal units
lb/MW-hr	pound per megawatt-hour
LHV	lower heating value
m	meter
MACT	Maximum Available Control Technology
MMBtu/hr	million British thermal units per hour
MMcf/hr	million cubic feet per hour
MPS	Mitsubishi Power Systems
MW	megawatt
NAAQS	National Ambient Air Quality Standards
NAD83	North American Datum 83
NESHAP	National Emission Standards for Hazardous Air Pollutants
N_2O	nitrous oxide
NO_2	nitrogen dioxide
NO_x	nitrogen oxides
NP	National Park
NSPS	New Source Performance Standards
NSR	New Source Review
NWA	National Wilderness Area
NWS	National Weather Service
O_2	oxygen
PFCs	perfluorocarbons
PFM	Plant Fort Myers the abbreviation for the FPL Fort Myers Plant
PM	particulate matter
$PM_{2.5}$	particulate matter less than 2.5 microns
PM_{10}	particulate matter less than 10 microns
ppb	parts per billion
ppbvd	parts per billion by volume dry
ppm	parts per million

ppmvd	parts per million by volume dry
PSD	Prevention of Significant Deterioration
psia	pound per square inch absolute
psig	pound per square inch gauge
QA/QC	quality assurance/quality control
RICE	reciprocating internal combustion engines
SAM	sulfuric acid mist
scf/yr	standard cubic foot per year
SCR	selective catalytic reduction
SCRAM	Support Center for Regulatory Air Models
SER	significant emissions rate
SIL	significant impact level
SF_6	sulfur hexafluoride
SO_2	sulfur dioxide
S.R.	State Road
ST	steam turbine
TPY	tons per year
TSP	total suspended particulate
TTN	Technology Transfer Network
ULSD	ultra low sulfur distillate "light oil"
USGS	U.S. Geological Survey
UTM	Universal Transverse Mercator
VOC	volatile organic compound
WCEC	West County Energy Center

1.0 INTRODUCTION

Florida Power & Light Company's (FPL's) existing Fort Myers Plant is located in Lee County Florida (see Figure 1-1) and includes one block of 12 simple cycle gas turbines (GT1 through GT12). GT Units 1 through 12 (EUs 003 through 014) began operation in May 1974. Each GT has a gross capacity of 63 megawatts (MWs). GT Units 1 through 12 are currently authorized to operate under Florida Department of Environmental Protection (FDEP) Title V Permit No. 0710002-016-AV on No. 2 distillate oil and specification used oil.

The existing 12 GTs located at the Fort Myers Plant are early generation gas turbine units that are used to serve peak and emergency demands in a quick start manner. These units have low stack heights (less than 50 feet) and relatively high nitrogen oxides (NO_X) emissions rates typical of these older generation units. NO_X emissions principally consist of nitrogen oxide (NO) and nitrogen dioxide (NO_2). The low stack heights in proximity to nearby property boundaries result in decreased dispersion properties and when combined with the relatively high NO_X emission rates result in elevated concentrations of NO_2. A new 1-hour national ambient air quality standard (NAAQS) has been recently promulgated by EPA and adopted by FDEP that is much more stringent than the previous annual average NAAQS for NO_2. Analyses of these existing 12 GT units found that the emissions from these units would not disperse sufficiently to bring off-site concentrations below the 1-hour NO_2 NAAQS. FPL's evaluation concluded that the most cost effective solution is to replace the existing GTs with new, highly efficient combustion turbines with lower NO_X emission rates. FPL, after consultations and agreement with FDEP understands that completing this project as expeditiously as possible is necessary to FDEP's implementation of the NAAQS Program and Section 172 of the Clean Air Act. Thus FPL plans to bring three new CTs into service by December 31, 2016, that would assure 1-hour NO_2 concentrations do not exceed the NAAQS at the property boundary.

This Air Construction Permit/Prevention of Significant Deterioration (PSD) Application consists of the retirement (except potentially two GTs to be retained for emergency black start capability only) of the existing Fort Myers GTs (GT1 through GT12) and replacement with three nominal 200 MW combustion turbines (CTs), effectively changing out the combustion technology of FPL's peaking resources to reduce emissions. These three CTs will be located at FPL's Fort Myers Plant and will be referred to as the Fort Myers CT Project ("Project"). The new CTs will be designated Units 3C through 3E.

Dismantlement of the existing generation units will occur after the new CTs are operational in order to maintain peak service capability in south Florida. There will be no overlap of operation between the existing GT units and new CTs.

There will be significant benefits associated with the Project. The three new CTs will be more energy efficient than the existing 12 GTs and will provide cleaner energy to FPL's customers. For the same amount of generation hourly, from 30 to 40 percent less fuel will be used in the new CT units compared to the older GT units. The maximum total air quality impacts for the Project are predicted to be well below and in compliance with the NAAQS. For pollutants such as NO_2, the Project's total air quality impacts are predicted to be significantly 40 percent or more lower than those predicted for the existing GTs.

In addition, air emission rates for NO_x with the Project will be approximately 90 percent lower than the existing GT emission rates, resulting in significantly lower air quality impacts.

The CTs being evaluated for the Project include the General Electric 7FA.05 and 7FA.04 CTs, and Siemens Power Generation, Inc. (Siemens) SGT6-5000F(5) CTs, or other vendor equivalents. The GE FA.05 CT has higher mass flow and produces more generation than the 7FA.04 CT. As a result, the emissions from GE FA.04 CT are enveloped by the GE FA.05 CT for the same emission rates (e.g., ppmvd; lb/MMBtu). Therefore, the GE 7FA.05 information was used for the analyses in this application. The information presented in this application envelops the performance and emissions for the above noted CTs being considered.

Each CT may utilize inlet air cooling and may consist of evaporative cooling or an alternative system. Evaporative cooling systems achieve adiabatic cooling using water in the form of water evaporated from a treated paper material. The evaporating water cools the inlet air stream when the water droplets are converted to water vapor. Inlet air temperature is reduced as heat is transferred at a rate of 1,075 British thermal units per pound (Btu/lb) of evaporated water. The result is a cooler, denser air stream. This allows additional power to be produced. The CTs will use natural gas and ultra low sulfur distillate (ULSD) oil as fuel. USLD oil will be used for up to the equivalent of 500 hours per year (hr/yr) per CT at base load conditions.

Natural gas will be transported to the facility via existing pipeline. ULSD oil will be delivered to the facility by truck and will be stored in two existing fuel oil storage tanks.

The U.S. Environmental Protection Agency's (EPA's) PSD regulations are promulgated under Title 40, Part 51.166 of the Code of Federal Regulations (40 CFR 51.166). Florida's PSD regulations are codified in FDEP Rule 62-212.400, Florida Administrative Code (F.A.C.), and have been approved by EPA. The Florida PSD regulations incorporate the requirements of EPA's PSD regulations. Under these requirements, the existing Fort Myers Plant is classified as an existing major facility. A modification to an existing major facility that results in a significant net emissions increase equal to or exceeding the significant emissions rates (SERs) listed in the Florida regulations under Section 62-212.400, Table

62-212.400-2, F.A.C., is classified as a major modification and will be subject to the PSD preconstruction permitting program for those pollutants that exceed the PSD SERs.

The procedures for determining applicability of the PSD permitting program to the Project are specified in FDEP Rule 62-212.400(2), F.A.C. For each regulated pollutant, PSD is triggered as a result of a modification at an existing facility if the difference between the projected actual emissions and the baseline actual emissions equals or exceeds the SER for that pollutant, as defined at FDEP Rule 62-210.200 (243), F.A.C.

On June 3, 2010, EPA promulgated regulations related to PSD and Title V GHG Tailoring Rule [75 Federal Register (FR) 31514-31608]. This change in EPA's PSD regulations requires PSD review and approval for new major projects and modifications exceeding the PSD thresholds for review. This application includes information to address PSD review of GHGs under EPA's rules. Florida has deferred review and approval of projects undergoing PSD review for GHGs to EPA Region 4.

Using the required regulatory comparison of potential to baseline actual emissions when adding new emission units, there will be significant net increase in some regulated air emissions for the Project including GHGs. The net changes in air emissions, as presented in Section 2.0, will exceed the PSD SERs for many of the criteria pollutants subject to PSD review and GHGs. Therefore, pursuant to FDEP Rule 62-212.400, F.A.C., PSD review is applicable for the Project.

This Application is being filed for the purpose of obtaining an air construction/PSD permit for the Project in accordance with FDEP's federally approved major source air construction permit program under Florida's federally required State Implementation Plan. A separate application will be submitted to EPA Region 4 for PSD review and approval of GHG emissions. This Air Construction Permit Application Report is divided into seven major sections.

- Section 1.0 presents an introduction to the Project
- Section 2.0 presents a description of the Project, including air emissions and stack parameters
- Section 3.0 provides a review of the regulatory analysis conducted, including PSD and nonattainment requirements, applicable to the Project
- Section 4.0 includes the control technology review including a Best Available Control Technology (BACT) analysis including GHG
- Section 5.0 discusses the ambient air monitoring analysis
- Section 6.0 presents a summary of the air modeling approach and results used in assessing compliance of the Project with NAAQS and PSD Increments.

- Section 7.0 presents the additional impact analysis required for PSD review.
- Appendices which include emission calculations, historical operation, BACT determinations and FDEP Form No. 62-210.900(1): Application for Air Permit – Long Form.

2.0 PROJECT DESCRIPTION

2.1 Facility Description

The existing FPL Fort Myers Plant is located within unincorporated Lee County, Florida. The existing plant is situated within approximately 460 acres of land owned by FPL. The facility is located on Palm Beach Boulevard (Stet Road 80), Fort Myers, Florida. Figure 2-1 presents the conceptual facility plot plan for the Project.

2.2 New Combustion Turbines

The CTs (any of the models under consideration or equivalent) will use low-NO_x combustion technology or equivalent when firing natural gas and water injection when firing ULSD oil to minimize formation of NO_x. Natural gas and ULSD oil will be used as fuel. While FPL envisions that the new CTs will be operated as peaking and emergency capacity like the existing GTs, FPL is conservatively seeking permitting authority for maximum operation of 3,390 hr/yr (base load equivalent hours) for each CT of which USLD oil usage is up to 500 hr/yr (base load equivalent hours) for each CT. This is an accepted operating assumption for permitting simple-cycle combustion turbine units in Florida.

The generating capacity of a CT is affected by ambient temperature, with increased temperature resulting in slightly less efficient electric production. Greater overall fuel consumption can occur at lower ambient temperatures. For the purpose of calculating maximum hourly fuel use quantities, the following specific operating conditions were used for the CTs (see Appendices A and B):

- 35 degrees Fahrenheit (°F) dry bulb turbine inlet temperature
- 60 percent relative humidity

The maximum heat input for the CTs being considered for the Project ranges from 1,754 MMBtu/hr, LHV (1,946 MMBtu/hr, HHV), to 2,022 MMBtu/hr, LHV (2,246 MMBtu/hr, HHV), when firing natural gas (100 percent capacity, 35°F). The corresponding maximum fuel usage ranges from about 2.2 million cubic feet per hour (MMcf/hr) to 1.9 MMcf/hr of natural gas for each CT. Maximum potential fuel usage at 75°F turbine inlet temperature ranges from about 2.9×10^{10} cubic feet per year (cf/yr) to 3.8×10^{10} cf/yr of natural gas for the Project operating 3,390 hours per year.

ULSD oil use will be based on the equivalent of 500 hr/yr per CT at full load. The maximum fuel use is about 16,500 gallons per hour per CT at 35°F turbine inlet with a maximum annual usage rate of 41 million gallons for three CTs each operating for 500 hours.

2.3 Source Emission Units and Stack Parameters

The Project's air emission units are:

- 3 simple cycle CTs
- Black start generators (or retain two existing GTs for black start capability),

Each of these emission units is discussed in the following paragraphs.

Performance, estimated maximum hourly emissions, and exhaust information representative of each CT option operating at base load conditions (100 percent load) in simple cycle are presented in Tables 2-1a and 2-1b, and Tables 2-2a and 2-2b for natural gas and ULSD oil firing, respectively. Tables 2-1a and 2-1b and 2-2a and 2-2b are presented as versions "a" and "b", which are representative of the GE FA.05 and Siemens F5 CT models, respectively. The data are presented for a turbine inlet temperature of 75°F. The performance and emissions data for the other operating conditions are given in Appendices A and B for turbine inlet temperatures of 35°F, 75°F, and 95°F and various operating load conditions. Appendix A presents information on both the GE 7FA.05 and 7FA.04 models.

Maximum potential annual emissions for the CTs for regulated air pollutants using a turbine inlet temperature of 75°F. This turbine inlet temperature is conservative, since the annual average temperature is slightly higher than 75°F. To produce the maximum annual emissions, it is assumed that each CT would operate for 3,390 hours (except for maximum emissions of SO_2). Of the 3,390 operating hours, an average of 2,890 hr/yr is assumed to be natural gas firing. For the remaining average of 500 hr/yr, the CTs are assumed to operate on ULSD oil.

Since the ULSD (0.0015 percent) oil has lower fuel sulfur content than that assumed for natural gas (2 gr/100 scf), the maximum annual SO_2 and sulfuric acid mist (SAM) emissions are based on 3,390 hours of operation firing natural gas. Tables 2-3a and 2-3b present the maximum potential annual emissions for the range of operating conditions for each CT being considered for the Project.

A process flow diagram of the new CT configuration, operating at base load conditions with a compressor inlet temperature of 75°F, is presented in Figure 2-2.

During combustion, two primary types of NO_x are formed: fuel NO_x and thermal NO_x. Fuel NO_x emissions are formed through the oxidation of a portion of the nitrogen contained in the fuel. Thermal NO_x emissions are generated through the oxidation of a portion of the nitrogen contained in the combustion air. NO_x formation can be limited by lowering combustion temperatures (through water injection) and/or staging combustion (a reducing atmosphere followed by an oxidizing atmosphere). Emissions of NO_x for the CTs are proposed at concentrations of 9 parts per million by volume dry (ppmvd) conditions, corrected to 15 percent oxygen (O_2) when firing natural gas and 42 ppmvd corrected to 15 percent O_2 when firing ULSD oil.

Carbon monoxide (CO) is formed by incomplete combustion of fuel. High combustion temperatures, adequate excess air, and good fuel/air mixing during combustion will minimize CO formation. CO formation is limited by ensuring complete efficient combustion of the fuel in the turbines. Recent improvements in CT combustor technology allow for both reduced NO_x emissions and low CO emissions.

The expected CO stack emission rates at base load for the GE CTs or equivalent when firing natural gas are 9 ppmvd operation and 20 ppmvd with ULSD oil firing. For the Siemens CTs, the expected CO emission rates at base load when firing natural gas are 4 ppmvd corrected to 15 percent O_2 when firing gas, and 9 ppmvd corrected to 15 percent O_2 with ULSD oil firing.

Similarly, volatile organic compound (VOC) emissions are formed by incomplete combustion of fuel. High combustion temperatures, adequate excess air, and good fuel/air mixing during combustion will minimize VOC formation. VOC formation is limited by ensuring complete efficient combustion of the fuel in the CTs. Recent improvements in CT combustor technology allow for both reduced NO_x emissions and low VOC emissions.

The expected VOC emission rates for the GE CTs or equivalent at base load operation when firing natural gas are 1.4 ppmvd corrected to 15 percent O_2 at base load operation and 3.5 ppmvd corrected to 15 percent O_2 for ULSD oil firing. For the Siemens CTs or equivalent at base load operation, the expected VOC emission rates when firing natural gas are 1.0 ppmvd corrected to 15 percent O_2 at base load operation and 1.0 ppmvd corrected to 15 percent O_2 for ULSD oil firing.

SO_2 emission rates are controlled and minimized by the very low sulfur content in the fuels, which will be a maximum of 2 gr/100 scf sulfur for natural gas and 0.0015 percent sulfur by weight for ULSD oil.

The Project may be equipped with four nominal 3,000 kilowatt (kW) emergency generators firing ULSD oil for black start capability. These emergency generators will be used when electric power is not available to start the CTs. This primarily would occur during catastrophic events such as hurricanes. Table 2-4 contains representation performance and emissions information for the black start diesel generators proposed for the Project, based on 100 hr/yr operation for permitting purposes. Normally these emergency generators would be operated 1 to 2 hours per month for maintenance and reliability testing. Alternatively, two of the 24 existing gas turbines may be kept to provide this black start capability.

2.4 Annual Emissions for the Project

The maximum annual potential emissions for the Project include air emissions from the CTs and emergency generators. Tables 2-5a and 2-5b present the maximum annual potential emissions with the GE and Siemens CTs, respectively. These tables address the criteria pollutants, as required, under new source review.

In addition, maximum annual potential hazardous air pollutants (HAPs) emissions are presented in Tables 2-6a and 2-6b for GE 7FA.05 and Siemens F5 CT models, respectively. Additional detail on the HAP emission calculations is also presented in Appendices A and B. The Fort Myers Plant will continue to be a major source of hazardous air pollutant (HAP) emissions due to the combined potential emissions from the Project and existing combined cycle unit exceed the major source for HAPs [10 tons per year (TPY) of a single HAP, or 25 TPY for all HAPs].

Annual emissions were based on maximum emissions for base load operation and ambient temperatures of 75°F. The maximum emissions of all regulated air pollutants except SO_2 are based on 2,890 hr/yr firing natural gas and 500 hr/yr firing oil. The maximum SO_2 emissions are based on natural gas firing for 3,390 hr/yr. The potential emissions are based 100 percent load condition at a turbine inlet temperature of 75°F, since this temperature represents a conservative annual average temperature for the area.

Tables 2-5a and 2-5b compare the net emission changes due to the Project, reflecting the maximum Project emissions as well as the emission reductions from retirement of the existing GT Units 1 through 12, to the PSD SERs. The PSD SERs are the emission thresholds to determine if PSD review will be required for modifications to major sources. The historical actual emissions for the existing GT Units 1 through 12 that are presented in these tables were determined pursuant to FDEP PSD Rules, specifically FDEP Rule 62-212.400 (2)(a)1., F.A.C. Five years (2008 through 2012) of historical emission data were evaluated to determine historical actual emissions using the highest 2 year average emissions for each pollutant. Historical actual emissions are based on past Annual Operating Reports (AORs), which are presented in a series of tables in Appendix C for each unit for each year. In Tables 2-5a and 2-5b, the net emission changes (i.e., projected maximum potential emissions minus historical actual emissions) are compared to the PSD SERs. If the PSD SER for a pollutant is not exceeded by this comparison, PSD review is not required for that pollutant.

As shown in these tables, there are significant net emission increases for most pollutants. Therefore, PSD review is required for particulate matter (PM), particulate matter less than 10 microns (PM_{10}), particulate matter less than 2.5 microns ($PM_{2.5}$), and NO_x, CO, VOCs and GHG.

2.5 Annual Emissions for GHGs

On June 3, 2010, EPA promulgated regulations related to Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule (75 FR 31514-31608). In EPA's promulgation, GHGs are defined to include an aggregate group of six GHGs: CO_2, methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6). Each of these GHGs has a specific Global Warming Potential that is calculated as "CO_2 equivalent emissions" or CO_2e that is equivalent to one ton of CO_2.

For the Project, the GHGs emitted are CO_2, CH_4, and N_2O with one ton of CH_4 equivalent to 21 tons of CO_2e and one ton of N_2O equivalent to 310 tons of CO_2e. Tables 2-5a to 2-5b present the net emission changes resulting from the Project, reflecting the maximum projected the Project emissions and the resulting changes compared to the existing GT Units 1 through 12 and the PSD SERs, which are thresholds for PSD review for modifications to major sources.

GHGs were calculated based on the actual annual heat input and emission factors from 40 CFR 98, Subpart C. These GHG emissions show the CO_2e rates for these pollutants. PSD review is required for GHG emissions greater than the listed PSD SER of 75,000 tons CO_2e. For PSD applicability purposes, Tables 2-5a and 2-5b, show the maximum potential emission of GHGs will exceed the baseline actual emissions of GT Units 1 through 12, primarily due to greater assumed operation than the existing GTs. A separate application will be submitted to EPA Region 4 for PSD review and approval of GHG emissions.

2.6 Layout, Structures, and Stack Sampling Facilities

A conceptual facility plot plan of the Project is presented in Figure 2-1. Typical dimensions of the structures associated with the CTs are presented in Section 6.0. Stack sampling facilities will be constructed in accordance with FDEP Rule 62-297.310(6), F.A.C.

2.7 Excess Emissions

In addition to the excess emissions allowed pursuant to FDEP Rule 62-210.700, F.A.C., a provision for Combustion and Full Speed No Load (FSNL) tuning similar to that authorized for other CT in FPL's fleet is requested. The proposed condition follows:

> *Combustion Tuning / FSNL Testing: Continuous monitoring data collected during initial or other major combustion tuning sessions and during manufacturer required Full Speed No Load (FSNL) operations shall be excluded from the continuous monitoring compliance demonstration provided the tuning session is performed in accordance with the manufacturer's specifications. A "major tuning session" would occur after a combustor change-out, a major repair or maintenance to a combustor, or other similar circumstances. Prior to performing any major tuning session, the permittee shall provide the Compliance Authority with an advance notice of at least one working (business) day that details the activity and proposed tuning schedule. The notice may be by telephone, facsimile transmittal, or electronic mail. (from West County Energy Center Title V Facility 0990646)*

3.0 AIR QUALITY REVIEW REQUIREMENTS AND APPLICABILITY

The following discussion pertains to federal, state, and local air regulatory requirements and their applicability to the Project.

3.1 National, State, and Local AAQS

The existing applicable national and Florida AAQS are presented in Table 3-1. Primary NAAQS were promulgated to protect the public health with an adequate margin of safety and secondary NAAQS were promulgated to protect the public welfare from any known or anticipated adverse effects associated with the presence of pollutants in the ambient air. Areas of the country in compliance with NAAQS are designated as attainment areas. New sources to be located or modified sources located in or near these areas may be subject to more stringent air permitting requirements.

3.2 PSD Requirements

3.2.1 General Requirements

Under federally approved Florida PSD review requirements, all major new or modified sources of air pollutants regulated under the Clean Air Act (CAA) must be reviewed and a pre-construction permit issued.

PSD is applicable to a "major facility" and certain "modifications" that occur at a major facility. A major facility is defined as any 1 of 28 named source categories that have the potential to emit 100 TPY or more, or any other stationary facility that has the potential to emit 250 TPY or more, of any pollutant regulated under the CAA. "Potential to emit" means the capability, at maximum design capacity, to emit a pollutant after the application of control equipment. Net emission increases from a modification at a major facility that exceed the PSD SERs are also subject to PSD review.

EPA has promulgated regulations providing that certain increases above an air quality baseline concentration level of SO_2, PM_{10}, and NO_2 concentrations that would constitute significant deterioration. The EPA class designations and allowable PSD increments are presented in Table 3-1. Florida has adopted the EPA class designations and allowable PSD increments for SO_2, PM_{10}, and NO_2.

PSD review is used to determine whether significant air quality deterioration will result from the new or modified facility. Florida's PSD regulations are found in FDEP Rule 62-212.400, F.A.C. Major new facilities and major modifications are required to undergo the following analysis related to PSD for each pollutant emitted in significant amounts (see Table 3-2):

1. Control technology review,
2. Source impact analysis,
3. Air quality analysis (monitoring),
4. Source information, and
5. Additional impact analyses.

In addition to these analyses, a new major facility or major modification made to an existing major facility also must be reviewed with respect to Good Engineering Practice (GEP) stack height regulations. Discussions concerning each of these requirements for a new major facility or major modification are presented in the following sections.

3.2.2 Greenhouse Gases

On June 3, 2010, EPA issued a "Tailoring Rule" that "tailors" the applicability provisions of the PSD and Title V programs to enable EPA and state agencies to phase in permitting requirements for GHGs. The first phase of the Tailoring Rule began on January 2, 2011, and continued through June 30, 2011. During this period GHG sources became subject to PSD if the increase in GHG emissions from a project exceeded 75,000 TPY of CO_2e or more and the project was required to undergo PSD review for other air regulated pollutants. The second phase of the Tailoring Rule began on July 1, 2011, and continues thereafter for new major GHG emitting facilities and major modifications. New major sources with the potential to emit 100,000 TPY CO_2e or more of GHG will be considered major sources for PSD permitting purposes and are required to undergo PSD review. Additionally, any physical change or change in the method of operation at a major source resulting in a net GHG emissions increase of 75,000 TPY CO_2e or more will be subject to PSD review.

For PSD purposes, GHGs are a single air pollutant defined as the aggregate group of the following six gases: CO_2, N_2O, CH_4, HFCs, PFCs, and SF_6.

Once major sources become subject to PSD, these sources must meet the various PSD requirements in order to obtain a PSD permit. However, there are no ambient air quality standards or PSD increments for GHGs. Therefore, the requirements for a source impact analysis, air quality analysis (monitoring), and additional impact analyses are not required. PSD review for GHGs principally involves the control technology review that includes a determination of BACT. The EPA published the PSD and Title V permitting guidance for GHGs in March 2011 that provides guidance on BACT analyses for GHG emissions.

3.2.3 Control Technology Review

A new major facility or major modification must perform a control technology review, which requires that all applicable federal and state emission limiting standards be met and that BACT be applied to control emissions from the source (FDEP Rule 62-212.400, F.A.C.). The BACT requirements are applicable to all regulated pollutants for which the increase in emissions from the facility or modification exceeds the SER (see Table 3-2).

BACT is defined in FDEP Rule 62-210.200(40), F.A.C., as:

(a) *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, 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 taking into account:*

1. *Energy, environmental and economic impacts, and other costs,*

2. *All scientific, engineering, and technical material and other information available to the Department, and*

3. *The emission limiting standards or BACT determinations of Florida and any other State.*

(b) *If the Department determines that technological or economic limitations on the application of measurement methodology to a particular part of an emissions unit or facility would make the imposition of an emission standard infeasible, a design, equipment, work practice, operational standard or combination thereof, may be prescribed instead to satisfy the requirement for the application of BACT. Such standard shall, to the degree possible, set forth the emissions reductions achievable by implementation of such design, equipment, work practice or operation.*

(c) *Each BACT determination shall include applicable test methods or shall provide for determining compliance with the standard(s) by means which achieve equivalent results.*

(d) *In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR Parts 60, 61, and 63.*

The BACT requirements are intended to ensure that the control systems incorporated in the design of a new facility reflect the latest in control technologies used in a particular industry and take into consideration existing and future air quality in the vicinity of the new facility. BACT must, at a minimum, demonstrate compliance with NSPS for a source (if applicable). An evaluation of the air pollution control techniques and systems, including a cost-benefit analysis of alternative control technologies capable of achieving a higher degree of emission reduction than the proposed control technology, is required. The cost-benefit analysis requires the documentation of the materials, energy, and economic penalties associated with the proposed and alternative control systems, as well as the environmental benefits derived from these systems. A decision on BACT is to be based on sound judgment, balancing environmental benefits with energy, economic, and other impacts (EPA, 1978).

For GHG emissions, control technology review is conducted by EPA under its regulations in 40 CFR 52.21. EPA issued guidance on the determination of BACT for GHGs ("*PSD and Title V Permitting Guidance for Greenhouse Gases*", March 2011). This EPA guidance supplements previous EPA guidance on the determination of BACT that is specific to BACT determinations for GHG emissions.

3.2.4 Source Impact Analysis

A source impact analysis must be performed for a new major facility or major modification to a major source for each pollutant, subject to PSD review, for which net emissions exceed the SER (Table 3-2). The PSD regulations specifically provide for the use of atmospheric dispersion models in performing impact analyses, estimating baseline and future air quality levels, and determining compliance with AAAQS and allowable PSD increments. Designated EPA models that are approved by FDEP normally must be used in performing the impact analysis. Specific applications for other than EPA approved models require EPA's consultation and prior approval. Guidance for the use and application of dispersion models is presented in the EPA publication *Guideline on Air Quality Models (Revised)*. The source impact analysis for criteria pollutants to address compliance with NAAQS and PSD Class II increments may be limited to the new source if the impacts as a result of the new source are below significant impact levels, as presented in Table 3-1.

The EPA has proposed significant impact levels for Class I areas. Although these levels have not been officially promulgated as part of the federal PSD regulations and may not be binding for states in performing PSD reviews, the levels serve as a guideline in assessing a source's impact in a Class I area. FDEP has accepted the use of these significant impact levels.

Various lengths of meteorological data records can be used for impact analysis. A 5 year period can be used with corresponding evaluation of highest, second highest short term concentrations for comparison to NAAQS or PSD increments. The term "highest, second highest" (HSH) refers to the highest of the second highest concentrations at all receptors (i.e., the highest concentration at each receptor is discarded). The second highest concentration is significant because short term NAAQS specify that the standard should not be exceeded at any location more than once a year. If fewer than 5 years of meteorological data are used in the modeling analysis, the highest concentration at each receptor normally must be used for comparison to air quality standards.

Because there are no NAAQS or PSD increments applicable to GHG emissions, these analyses are not conducted for PSD review for GHG.

3.2.5 Air Quality Monitoring Requirements

In accordance with requirements of FDEP Rule 62-212.400(5)(f), F.A.C., PSD review for a new major facility or major modification must consider an analysis of continuous ambient air quality data in the area affected by the proposed major PSD source or major modification. For a new major facility or major modification, the affected pollutants are those that the facility potentially would emit above the SERs.

Ambient air monitoring for a period of up to 1 year generally is appropriate to satisfy the PSD monitoring requirements. Data for a minimum of 4 months are required. Existing data from the vicinity of the proposed source may be used, if the data meet certain quality assurance requirements; otherwise, additional data may need to be gathered. Guidance in designing a PSD monitoring network is provided in *Ambient Monitoring Guidelines for Prevention of Significant Deterioration* (EPA, 1987a).

The regulations include an exemption that excludes or limits the pollutants for which an air quality analysis must be conducted. This exemption states that a proposed major stationary facility is exempt from the monitoring requirements with respect to a particular pollutant, if the emissions of the pollutant from the facility would cause, in any area, air quality impacts less than the *de minimis* levels presented in Table 3-2 (FDEP Rule 62-212.400-3, F.A.C.). If a facility's predicted impacts are less than the *de minimis* levels, then preconstruction monitoring is not required.

Because there are no ambient monitoring methods applicable to GHG emissions, these analyses are not conducted for PSD review for GHG.

3.2.6 Source Information/GEP Stack Height

Source information must be provided to adequately describe the proposed facility or major modification subject to PSD review.

The 1977 CAA Amendments require that the degree of emission limitation required for control of any pollutant cannot be affected by a stack height that exceeds GEP or any other dispersion technique. On July 8, 1985, EPA promulgated final stack height regulations (EPA, 1985a). Identical regulations have been adopted by FDEP (FDEP Rule 62-210.550, F.A.C.). GEP stack height is defined as the highest of:

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

$$Hg = H + 1.5\,L$$

where:

Hg = GEP stack height,

H = Height of the structure or nearby structure, and

L = Lesser dimension (height or projected width) of nearby structure(s); or

3. A height demonstrated by a fluid model or field study.

"Nearby" is defined as a distance up to 5 times the lesser of the height or width dimensions of a structure or terrain feature, but not greater than 0.8 kilometer (km). Although GEP stack height regulations require that the stack height used in modeling for determining compliance with NAAQS and PSD increments not exceed the GEP stack height, the actual stack height may be greater.

The stack height regulations also allow increased GEP stack height beyond that resulting from the above formula in cases where plume impaction occurs. Plume impaction is defined as concentrations measured or predicted to occur when the plume interacts with elevated terrain. Elevated terrain is defined as terrain that exceeds the height calculated by the GEP stack height formula.

3.2.7 Additional Impact Analysis

In addition to air quality impact analyses, Florida PSD regulations require analyses for applicable pollutants of the impairment to visibility and the impacts on soils and vegetation that would occur as a result of a new major facility or major modification subject to PSD review [FDEP Rule 62-212.400(5)(e), F.A.C.]. Impacts as a result of general commercial, residential, industrial, and other growth associated with the source also must be addressed. These analyses are required for each pollutant emitted in significant amounts (see Table 3-2).

Because GHG emissions will not cause visibility impairment or direct impacts to soils and vegetation, these analyses are not conducted for PSD review for GHG.

3.2.8 Air Quality Related Values

An Air Quality Related Value (AQRV) analysis is required for projects for those pollutants undergoing PSD review to assess the potential impact on AQRVs in PSD Class I areas. The nearest Class I areas to the Project are the Everglades National Park (ENP), located about 48 km (29 miles) from the Project, and the Chassahowitzka National Wilderness Area (NWA), located more than 300 km (180 miles) from the Project. The U.S. Department of the Interior in 1978 administratively defined AQRVs to be:

> *All those values possessed by an area except those that are not affected by changes in air quality and include all those assets of an area whose vitality, significance, or integrity is dependent in some way upon the air environment. These values include visibility and*

those scenic, cultural, biological, and recreational resources of an area that are affected by air quality.

Important attributes of an area are those values or assets that make an area significant as a national monument, preserve, or primitive area. They are the assets that are to be preserved if the area is to achieve the purposes for which it was set aside (Federal Register, 1978).

The AQRVs include visibility, freshwater and coastal wetlands, dominant plant communities, unique and rare plant communities, soils and associated periphyton, and the wildlife dependent on these communities for habitat. Rare, endemic, threatened, and endangered species of the NP and bioindicators of air pollution (e.g., lichens) must also be evaluated.

3.3 Nonattainment Rules

FDEP has nonattainment provisions (FDEP Rule 62-212.500, F.A.C.) that apply to all new major facilities or major modifications to major facilities located in a nonattainment area. In addition, for these facilities that are located in an attainment or unclassifiable area, the nonattainment review procedures apply if the source or modification is located within the area of influence of a nonattainment area. The Project is located in Lee County, which is classified as an attainment area for all criteria pollutants. Therefore, nonattainment New Source Review (NSR) requirements are not applicable.

3.4 Emission Standards

3.4.1 New Source Performance Standards

The NSPS are a set of national emission standards that apply to specific categories of new sources. As stated in the 1977 CAA Amendments, these standards "shall reflect the degree of emission limitation and the percentage reduction achievable through application of the best technological system of continuous emission reduction the Administrator determines has been adequately demonstrated."

The Project will be subject to one or more NSPS. EPA promulgated new NSPS for Stationary Combustion Turbines that will commence construction after February 18, 2005. Subpart KKKK replaces Subpart GG for CTs.

Combustion Turbine

NO_x and SO_2 emissions from all stationary CTs with a heat input at peak load equal to 10.7 gigajoules per hour (10 MMBtu/hr), based on the lower heating value of the fuel fired, are limited per 40 CFR 60 Subpart KKKK. NO_x emissions for these new CTs (i.e., >850 MMBtu/hr) are limited by Subpart KKKK to 15 ppmvd corrected to 15 percent O_2 and 42 ppmvd corrected to 15 percent O_2 for natural gas and oil firing, respectively. SO_2 emissions are limited to using a fuel with a sulfur content of no greater than

0.05 percent and 20 gr/10 scf of sulfur for oil and natural gas firing, respectively. In addition to emission limitations, there are requirements for performance testing and monitoring in 40 CFR 60 Subpart KKKK.

There are also applicable notification, reporting, and recordkeeping requirements in the general provisions of 40 CFR 60 Subpart A. These are summarized below:

40 CFR 60.7 Notification and Record Keeping

(a)(1) Notification of the date of construction - 30 days after such date.

(a)(3) Notification of actual date of initial startup - within 15 days after such date.

(a)(5) Notification of date which demonstrates CEM - not less than 30 days prior to date

60.7 (b) Maintain records of all startups, shutdowns, and malfunctions.

(c) Excess emissions reports – semi-annually by the 30th day following 6-month period (required even if no excess emissions occur).

(d) Maintain file of all measurements for 2 years.

60.8 Performance Tests

(a) Must be performed within 60 days after achieving maximum production rate, but no later than 180 days after initial startup.

(d) Notification of Performance tests at least 30 days prior to them occurring.

Other Emission Units

NSPS are also applicable to the black start generators. For the project the black start diesel generators meet the definition of "emergency stationary internal combustion engine"

in NSPS Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines. This NSPS is applicable and the black start generators would be operated for according to Section 60.4211(f).

3.4.2 National Emission Standards for Hazardous Air Pollutants

EPA has promulgated maximum achievable control technology (MACT) standards under the National Emissions Standards for Hazardous Air Pollutants (NESHAPs) regulations. Maximum annual potential HAPs emissions were presented in Tables 2-6a and 2-6b for the GE 7FA.05 CTs and Siemens "F5" CTs, respectively. Additional detail on the HAP emission calculations is also presented in Appendices A and B.

The Fort Myers Plant remains a major source of HAPs due to the combined emissions of Units 4 and 5 and the potential emissions associated with the Project. Therefore, certain MACT standards under the NESHAP regulations would apply. Under the NESHAPs of 40 CFR Part 63, Subpart YYYY applies to the

CTs and Subpart ZZZZ applies to the reciprocating internal combustion engines (RICE). For the later, meeting the requirements of NSPS Subpart IIII meets the requirements of NESHAP Subpart ZZZZ.

3.4.3 Florida Rules

FDEP has adopted the EPA NSPS by reference in FDEP Rule 62-204.800(7): Subsection (b)39 for stationary gas turbines and Subsection (b)16 for volatile organic liquid storage vessels. Therefore, the facility is required to meet the same emissions, performance testing, monitoring, reporting, and record keeping as those described in Section 3.4.1. FDEP has authority for implementing NSPS requirements in Florida.

3.4.4 Florida Air Permitting Requirements

The FDEP regulations require any new source to obtain an air permit prior to construction. Major new sources must meet the appropriate PSD and nonattainment requirements as discussed previously. Required permits and approvals for air pollution sources include NSR for nonattainment areas, PSD, NSPS, NESHAP, Permit to Construct, and Permit to Operate. The requirements for construction permits and approvals are contained in FDEP Rules 62-4.030, 62-4.050, 62-4.210, 62-210.300(1), and 62-212.400, F.A.C. Specific emission standards are set forth in Chapter 62-296, F.A.C.

This Application is being filed for the purpose of establishing federally enforceable emission limitations that ensure the Project will not result in a significant net increase in emissions of any regulated air pollutant, in accordance with FDEP's federally approved minor source air construction permit program under Florida's federally approved SIP.

3.4.5 Local Air Regulations

There are no local air pollution regulations in Lee County. The FDEP South District located in Fort Myers is the air compliance authority for the county..

3.5 Source Applicability

3.5.1 Area Classification

The Project is located in Lee County, which has been designated by EPA and FDEP as an attainment area (includes unclassifiable) for all criteria pollutants. Lee County and surrounding counties are designated as PSD Class II areas for SO_2, PM [total suspended particulate (TSP)], and NO_2. The nearest Class I area to Project is the ENP, located approximately 97 km (60 miles) from the Project, and Chassahowitzka NWA, located more than 300 km (180 miles) from the Project.

3.5.2 PSD Review

Pollutant Applicability

The FPL Fort Myers Plant is considered to be a major facility under FDEP PSD rules because the emissions of several regulated pollutants are will exceed 100 TPY and the emissions units are one of the 28 listed major source categories under the PSD rules. The Project is defined as a major modification under the PSD rules and PSD review is required for any pollutant for any PSD-regulated air emissions that exceed the PSD significant emission rates. As shown in Table 3-3, potential emissions from the proposed Project will trigger PSD review for PM (TSP), PM_{10}, $PM_{2.5}$, NO_x, CO, and VOC. (Note: EPA no longer requires PSD review for HAPs from PSD review. The pollutants vinyl chloride, asbestos, and beryllium are no longer evaluated in PSD review because they are addressed through the NESHAP program.)

Emission Standards

NO_x and SO_2 emissions from all stationary CTs with a heat input at peak load equal to 10.7 gigajoules per hour (10 MMBtu/hr), based on the lower heating value of the fuel fired, are limited per 40 CFR 60 Subpart KKKK adopted by reference by FDEP in Rule 62-204.800(8)(b)78 F.A.C.. NO_x emissions for these new CTs (i.e., >850 MMBtu/hr) are limited by Subpart KKKK to 15 ppmvd corrected to 15 percent O_2 and 42 ppmvd corrected to 15 percent O_2 for natural gas and oil firing, respectively. SO_2 emissions are limited to using a fuel with a sulfur content of no greater than 0.05 percent and 20 gr/100 scf of sulfur for oil and natural gas firing, respectively. These requirements are summarized in Section 4.2. In addition to emission limitations, there are requirements for performance testing and monitoring in 40 CFR 60 Subpart KKKK. There are also applicable notification, reporting, and recordkeeping requirements in the general provisions of 40 CFR 60 Subpart A. The proposed emissions for CTs being considered for the Project will be well below the specified limits (see Section 4.0).

EPA has promulgated MACT standards under the NESHAP regulations and applicability is based on whether a source is major or minor for HAPs. A facility is classified as a major source of HAPs when the maximum potential emissions for all emission units located at the facility exceed 10 TPY of a single HAP and 25 TPY for all HAPs. The Fort Myers Plant will remain a major source of HAPs due to the combined potential emissions of the Project along with the existing combustion turbines associated with Units 4 and 5.

The NESHAP Subpart YYYY applies to the CTs being considered if the aggregate use of oil by existing and new turbines exceeds 1,000 hours during any calendar year. However, information available from the equipment vendors indicate that the CTs being considered will meet the proposed MACT of 91 parts per billion by volume dry (ppbvd) corrected to 15 percent O_2 for formaldehyde. FDEP adopted this EPA rule by reference in Rule 62-204.800(11)(b)81 F.A.C.

The NESHAP Subpart ZZZZ addressing RICE applies to both major and area sources of HAPs. FDEP adopted this EPA rule by reference in Rule 62-204.800(11)(b)82, F.A.C. The method of compliance under this rule is demonstrating compliance with 40 CFR 60, Subpart IIII, which was previously cited in this section. The emergency generators and fire pump engine will meet the requirements of Subpart IIII.

Ambient Monitoring

For the Project, the impacts will be less than the PSD de minimis monitoring concentrations for certain pollutants (see Section 5.0). As a result, an air quality monitoring impact analysis for these pollutants is not required by NSR under FDEP air regulations. For O_3 and $PM_{2.5}$, air quality monitoring data are provided, which demonstrate that Lee County is in attainment of the NAAQS for these pollutants. These data are presented in Section 5.0 of this application.

GEP Stack Height Impact Analysis

The GEP stack height regulations allow any stack to be at least 65 meters (213 ft) high. The CT stacks will be 80 ft. These stack heights do not exceed the GEP stack height. However, as discussed in Section 6.0, Air Quality Modeling Approach, since the stack height is less than GEP, building downwash effects must be considered in the modeling analysis. As a result, the potential for downwash of the CT emissions caused by nearby structures is included in the modeling analysis.

3.5.3 Local Air Regulations

As specified in Subsection 3.4.5, there are no local air pollution regulations in Lee County; therefore, permitting requirements for the Project will comply with FDEP permitting requirements.

3.5.4 Other Clean Air Act Requirements

The 1990 CAA Amendments established a program to reduce potential precursors of acidic deposition. The Acid Rain Program was delineated in Title IV of the CAA Amendments and required EPA to develop the program. EPA's final regulations were promulgated on January 11, 1993, and included permit provisions (40 CFR 72), allowance system (Part 73), continuous emission monitoring (CEM) (Part 75), excess emission procedures (Part 77), and appeal procedures (Part 78). FDEP adopted these rules by reference in Rule 62-204.800(16) F.A.C. (permit provisions), Rule 62-204.800(17) F.A.C. (allowance system), Rule 62-204.800(19) F.A.C.[continuous emission monitoring (CEM)], Rule 62-204.800(21) F.A.C. (excess emission procedures), and Rule 62-204.800(22) F.A.C. (appeal procedures).

EPA's Acid Rain Program applies to all existing and new utility units, except those serving a generator less than 25 MW, existing simple cycle CTs, and certain non-utility facilities; units which fall under the program are referred to as affected units. The EPA regulations are applicable to the Project for the purposes for obtaining a permit and allowances, as well as emission monitoring. New units are required to obtain permits under the program by submitting a complete application 24 months before the date on which the unit commences operation (e.g., first fire).

The permit would require the units to hold SO_2 emission allowances. Emission limitations established in the Acid Rain Program are presumed to be less stringent than BACT for new units. An allowance is a market based financial instrument that is equivalent to 1 ton of SO_2 emissions. Allowances can be sold, purchased, or traded.

NO_x monitoring is required for natural gas-fired and oil-fired affected units using CEM or alternate procedures. SO_2 monitoring is also required, although use of CEM is optional. When an SO_2 CEM system is selected to monitor SO_2 mass emissions, a flow monitor is also required. Alternately, SO_2 emissions may be determined using procedures established in Appendix D, 40 CFR 75 (FDEP Rule 62-204.800(19)(b)4 F.A.C.; flow proportional oil sampling or manual daily oil sampling). CO_2 emissions must also be determined either through a CEM (e.g., as a diluent for NO_x monitoring) or calculation. Alternate procedures, test methods, and quality assurance/quality control (QA/QC) procedures for CEM are specified (Part 75, Appendices A through I; FDEP Rule 62-204.800(19)(b)1-9 F.A.C.). The acid rain CEM requirements including QA/QC procedures are, in general, more stringent than those specified in the NSPS for Subpart KKKK. New units are required to meet the requirements by not later than 90 days after the unit commences commercial operation.

4.0 CONTROL TECHNOLOGY DESCRIPTION

4.1 Introduction

4.1.1 Applicability and BACT Approach

The PSD regulations require new major stationary sources or major modifications to existing major sources to undergo a control technology review for each pollutant that may potentially be emitted above significant amounts. As discussed in previous sections, PSD review is required for the Project.

There are NSPS regulations which are applicable to emissions of NO_x and SO_2 from the CTs. NSPS are also applicable to the black-start generators and fire pump engine. For the project, the black start diesel generators and fire pump engine meet the definition of "emergency stationary internal combustion engine" in NSPS Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines. The Clean Air Act specifies that BACT cannot be less stringent than any applicable standard of performance under the NSPS standards, which were discussed in Section 3.5.2. Subsection 4.2 presents the BACT analysis for non-GHG pollutants including NO_x, CO, VOCs and $PM/PM_{10}/PM_{2.5}$.

The approach to the BACT analysis is based on the regulatory definitions of BACT, as well as consideration of EPA's current guidelines suggesting that a "top-down" approach be followed in BACT analyses. The CAA and corresponding implementing regulations require that a BACT analysis be conducted on a case by case basis taking into consideration the amount of emissions reductions that each available emissions reducing technology or technique would achieve, as well as the energy, environmental, economic and other costs associated with each technology or technique.

EPA has recommended since 1990 that permitting authorities use the five step "top down" BACT process to determine BACT. The top down process calls for all available control technologies for a given pollutant to be identified and ranked in descending order of control effectiveness. The permit applicant should first examine the highest ranked ("top") option. The top ranked options should be established as BACT unless the permit applicant demonstrates to the satisfaction of the permitting authority that technical considerations, or energy, environmental, or economic impacts justify a conclusion that the top ranked technology is not "achievable" in that case. If the most effective control strategy is eliminated in this fashion, then the next most effective alternative should be evaluated, and so on, until an option is selected as BACT.

EPA has broken down this "top down" process into the following five steps:

Step 1: Identify all available control technologies

Step 2: Eliminate technically infeasible options

Step 3: Rank remaining control technologies

Step 4: Evaluate most effective controls and document results

Step 5: Select the BACT

4.1.2 Overview of Control Technology

The use of clean fuels (natural gas and ULSD oil) and combustion controls will minimize air emissions and ensure compliance with applicable emission-limiting standards. Using clean fuels will minimize emissions of SO_2, sulfuric acid mist (SAM), $PM/PM_{10}/PM_{2.5}$ and other fuel bound contaminants. Combustion controls will minimize the formation of NO_x and the formation of CO and VOCs by combustor design. Further NO_x reduction will be achieved by water injection during oil firing. The combination of these techniques has been determined to represent BACT on previous projects based on an evaluation of economic, energy, and environmental impacts. The following subsections present a summary of the best available control technology and practices for the Project.

As discussed previously, the GE CTs, and the Siemens CTs were used to evaluate the air emissions and impacts of the Project. The CT vendor has not been selected. However, FPL desires to obtain guarantees of CT performance that will achieve the nominal generation of 200 MW while achieving emissions within the range of the emissions provided for the GE and Siemens CTs. In recent permitting actions, the FDEP has established BACT for heavy-duty simple-cycle industrial gas turbines like the ones proposed for this Project. These decisions established emission rates that were achieved through the use of advanced low-NOx combustors for limiting NO_X, the use of good combustion practices for control of CO and VOCs and clean fuels (natural gas and ULSD oil) for control of SO_2, SAM, PM_{10} and $PM_{2.5}$. The BACT proposed for the Project's CTs is consistent with these recent FDEP permits.

The Project CTs will have two modes of operation (dual fuel) for which a BACT analysis has been performed. The results of the analysis have concluded that the following emission limits constitute BACT for the project.

CTs—Natural Gas Fired

- The CTs will utilize state-of-the-art low-NO_X combustion technology which will achieve gas turbine exhaust NO_X levels of no greater than 9 ppmvd corrected to 15 percent O_2
- CO emissions will be limited to 9 ppmvd corrected to 15% O_2 at base load; and good combustion practices will be utilized.

- Emission of PM_{10} and $PM_{2.5}$ will be limited by firing primarily natural gas and 10-percent opacity.

CTs—ULSD Oil Fired

- The CT will utilize water injection to achieve gas turbine exhaust NO_X levels of no greater than 42 ppmvd corrected to 15 percent O_2
- CO emissions will be limited to 20 ppmvd at base load; and good combustion practices will be utilized
- Hours of operation will be limited to an equivalent to 500 hours per year per CT at base load
- Emission of PM_{10} and $PM_{2.5}$ will be limited by firing ULSD oil and 10 percent opacity

Emergency "Black-Start" Generators

- Emissions meeting the applicable requirement to 40 CFR Subpart IIII, Stationary Compression Ignition Internal Combustion Engines
- Hours of operation will be limited to provide electric power to start a CT if no power is available and will operate like an emergency stationary RICE generator (100 hr/yr)
- Emissions of PM_{10} and $PM_{2.5}$ will be limited by firing ULSD oil

Table 4-1 presents the proposed BACT emission limits for the Project.

4.2 Non-GHG Control Technology Review – BACT Analysis

4.2.1 Combustion Turbines

Nitrogen Oxides

Feasibility

A review of the most recent BACT determinations for similar projects (Appendix Tables D-1 and D-2) demonstrates that emission levels equal to those proposed for the Project, as a result of the proposed low NO_X combustion technology, have been approved by regulatory agencies as BACT for similar simple cycle CTs. Available information suggests that feasible control technologies available, and in order of highest to lowest control efficiency, for simple cycle CTs are as follows:

1. Selective catalytic reduction ("Hot" SCR)
2. Low NO_X combustion technology
3. Wet-injection for oil firing

SCONOx™ was an available technology in the previous decade but has not been installed nor demonstrated on large frame CT such as the "F" class combustion turbines in either simple cycle or more commonly combined cycle configurations. This technology is not considerable available or feasible for simple cycle CTs. Other available technologies such as NOxOut, Thermal DeNOx, NSCR, and XONON™ were evaluated and determined to be technically infeasible or not commercially demonstrated for the Project.

Technology Description

The "Top Down" BACT analysis was performed for the following alternatives:

1. Selective catalytic reduction (SCR) and advanced low-NO_x combustors at an emission rate of 2.5 ppmvd corrected to 15 percent O_2 when firing natural gas and 12 ppmvd when firing oil (typical for combined-cycle units).
2. Advanced low-NO_x combustors at an emission rate of 9 ppmvd corrected to 15 percent O_2 when firing gas
3. Wet Injection at an emission rate of 42 ppmvd corrected to 15 percent O_2 when firing oil

SCR is a post-combustion process where NO_X in the gas stream is reacted with ammonia in the presence of a catalyst to form nitrogen and water. The reaction occurs typically between 600°F and 750°F, which has limited SCR application primarily to combined cycle units where such temperatures occur in the heat-recovery steam generator (HRSG). Exhausts from simple cycle operation range up to 1,200°F, thus limiting the direct application of SCR on this mode of operation. Higher cost ceramic catalyst can accommodate temperatures up to 850 to 1,000°F and application have been installed on aero-derivative gas turbines. Most recently, Mitsubishi Power Systems America (MPSA) installed SCR on four large nominal 200 MW Siemens "F" Class CTs at the Marsh Landing facility in California. This application is natural gas only and required to meet LAER rather than BACT. The MPSA SCR system involves gas cooling to maintain temperatures in range applicable for SCR. In-duct cooling using ambient air would maintain temperatures in the applicable range of SCR with turbine flow of about 2,600,000 acfm and up to 1,200°F temperatures in the exhaust gas. This approach could be accomplished with an electric powered fan rated at about 2,000 hp (1,491 kW) as well as mixing/SCR chamber similar in six to a small HRSG. A similar application when firing distillate oil has not been demonstrated on a "F" Class simple cycle gas turbine.

Ammonium salts (ammonium sulfate and ammonium bisulfate) are formed by the reaction of sulfur oxides in the gas stream and ammonia. These salts are highly acidic, and special precautions in materials and ammonia injection rates must be implemented to minimize their formation. The use of natural gas and ULSD limit the potential for ammonium salts to cause corrosion but particulate matter is formed and emitted in the gas stream.

Ammonia injected in the SCR system that does not react with NO_X is emitted directly into the atmosphere and referred to as ammonia slip. In general, SCR manufacturers guarantee ammonia slip to be no more than 10 ppmvd.

While "hot" SCR is technically feasible for the Project, BACT emission levels equivalent to SCR control have not been permitted on similar sized simple cycle CTs by FDEP or any other state agency in EPA Region 4 (see Tables D-1 and D-2).

Low-NO_X combustion technology has been offered and installed by manufacturers to reduce NO_X emissions by inhibiting thermal NO_X formation through premixing fuel and air prior to combustion and providing staged combustion to reduce flame temperatures. NO_X emissions of 25 ppmvd (corrected to 15 percent O_2) and less have been offered by manufacturers for advanced combustion turbines. Advanced in this context are the larger (over 150 MW) and more efficient (higher initial firing temperatures and lower heat rate) combustion turbines. This technology is truly pollution prevention because NO_X emissions are inhibited from forming.

Wet injection was the first combustion technology introduced for combustion turbines (pre-1980s) and was the primary method of reducing NO_X emissions from CTs prior to the 1990s. Indeed, this method of control was first mandated by the NSPS to reduce NOx levels to 75 ppmvd (corrected to 15 percent O_2 and heat rate). Wet injection is still the primary means of reducing NO_X formation in the combustion process when firing oil. When firing ULSD oil, NO_X is limited using water injection to 42 ppmvd corrected to 15 percent O_2.

Although SCONOx™ was commercially available in the late 1990s and early 2000s, it was never demonstrated on "F" Class or larger combustion turbines in either combined cycle or simple cycle modes. The SCONOx™ system has been only operated on a 32 MW facility in California since 1996 and a 5 MW unit in Massachusetts since 1999. The scale up of this complicated technology should not be underestimated. The SCONOx™ technology installed on an "F" Class turbine would involve about a dozen or more different chambers of catalyst for absorption and regeneration. Every 15 to 30 minutes, dampers would be operated to isolate a particular catalyst chamber for regeneration. Each regeneration cycle must isolate the chamber so that O_2 is not introduced and regeneration gas (hydrogen) is introduced. Seal leaks could be significant as applied to the large volume flows associated with a "F" Class turbine. Although the amount of sulfur in natural gas is very low, the SCONOx™ catalyst is poisoned by sulfur compounds, requiring the installation of the SCOSOx™ to further remove sulfur compounds as part of the overall system. The ability of SCOSOx™ to further remove compounds that will poison the catalyst as part of the overall SCONOx™ system has not been demonstrated when firing ULSD oil. Recent contacts with vendors of SCONOx™ technology have indicated that application of SCONOx has not been applied on large (80 MW or larger) CTs.

The recent permitting trend for advanced simple-cycle combustion turbines is the use of low-NO_X combustors and water injection for ULSD oil firing (see Appendix D, Table D-2). Indeed, the recent simple cycle Florida project, Shady Hills Power Project, L.P. Unit Nos. 4 and 5, have been permitted with this technology in 2012. The Shady Hills project is a GE 7FA.05 CT rated at 210 MW and is allowed to operate 3390 hours per year including 500 hr/yr of ULSD oil.

As discussed previously, the new CTs will be fired with natural gas and ULSD oil will be used not to exceed an equivalent of 500 hr/yr per CT at base load conditions. The following sections present a summary of the economic, environmental, and energy impacts of the available, technically feasible, and demonstrated control technology and emission rate alternatives for the simple cycle units.

Impacts Analysis

Economic—The total capital costs of SCR for the Project exceed $15,000,000 per CT. The total annualized cost of applying SCR with low-NO_X combustion technology ranges from is approximately $3.3 million to $2.7 million. The incremental cost effectiveness of adding SCR to the low- NO_X combustors and water injection (for oil firing) is estimated at over $20,000 per ton of NO_X removed, based on 3,390 hours of operation with 500 hour of oil firing. Detail calculations (for both GE and Siemens CTs) are provided in Tables 4-2a, 4-2b, 4-3a and 4-3b. It should be noted that CTs associated with the Project are replacements for less efficient GTs with higher NO_X emission rates that are operated to supply high demand periods and provide fast-start power for unit outages or other factors that limit base load and intermediate load generation. The typical operation will be less than the potential emissions and therefore the actual cost per ton of NO_X removed will be much higher.

Environmental—As discussed in Section 1.0, the Project will replace 36 existing GTs that, with high NO_X emission rates and low stack heights, would not disperse emissions sufficiently to meet the new 1-hour NO_2 NAAQS. The Project will eliminate this potential air quality issue while provide more efficient electric power. The use of low-NOx combustor technology is truly "pollution prevention". While additional controls beyond low-NO_X combustors (i.e., SCR and SCR with water injection) would further reduce emissions slightly, the effect will not be significant. For example, the installation of hot SCR would reduce potential NO_X emissions by only 150 TPY per CT while causing emissions of ammonia and ammonium salts, such as ammonium sulfate and bisulfate. Ammonia emissions associated with SCR are expected to be up to 10 ppm based on reported experience; previous permit conditions have specified this level. Indeed, ammonia emissions could be as high as 46.7 TPY per unit at the end of the catalyst's life. Potential emissions of ammonium sulfate and bisulfate will increase emissions of PM_{10} and $PM_{2.5}$; up to 6.4 TPY per unit could be emitted.

The electrical energy required to run the SCR system and the back pressure from the turbine will reduce the available power from the Project. More importantly, the need for tempering air required 2,000 hp (1,491 kW) fans that would require 0.75 percent of the produced power or about 5,054 MWh per year. This power, which would otherwise be available to the electrical system, will have to be replaced. The replacement power will cause air pollutant emissions that would not have occurred without SCR. These "secondary" emissions, coupled with potential emissions of ammonia and ammonium salts, were calculated. As calculated, the net reduction in primary and secondary emissions with SCR when all criteria pollutants are considered will be up to 89 TPY. In addition to criteria pollutants, additional secondary emissions of carbon dioxide would be emitted and were calculated to be 4,746 TPY. As noted, the emissions including CO_2 would be greater with SCR than that proposed using low-NO_X combustion technology.

The replacement of the SCR catalyst will create additional economic and environmental impacts since certain catalysts contain materials that are listed as hazardous chemical wastes under Resource Conservation and Recovery Act (RCRA) regulations (40 CFR 261). In addition, SCR will require the construction and maintenance of storage vessels of anhydrous or aqueous ammonia for use in the reaction. Ammonia has potential health effects, and the construction of ammonia storage facilities triggers the application of at least three major standards: Clean Air Act (Section 112), Occupational Safety and Health Administration (OSHA) 29 CFR 1910.1000, and OSHA 29 CFR 1910.119.

Energy—Significant energy penalties occur with SCR. With SCR, the output of the CT may be reduced by about 1 percent more than with advanced low-NOx combustors. This penalty is the result of the SCR pressure drop, which would be about 10 (according to the SCR template) inches of water and would amount to about 1,560,000 kWh per year in potential lost generation. The energy required by the SCR equipment would be about 6,170,000 kWh per year including the tempering air fan. Taken together, the total lost generation and energy requirements of SCR of 7,740,000 kWh per year could supply the monthly electrical needs of about 645 residential customers. To replace this lost energy, an additional 74,900 British thermal units per year (Btu/yr) or about 75 million cubic feet per year (ft^3/yr) of natural gas would be required.

Technology Comparison—The Project will use an advanced heavy-duty industrial gas turbine with advanced low-NO_X combustors. This type of machine advances the state-of-the-art for CTs by being more efficient and less polluting than previous CTs. Integral to the machine's design is low-NO_X combustors that prevent the formation of air pollutants within the combustion process, thereby eliminating the need for add-on controls that can have detrimental effects on the environment. An analogy of this technology is a more efficient automotive engine that gives better mileage and reduces pollutant formation without the need of a catalytic converter.

An advanced gas turbine is unique from an engineering perspective in two ways. First, the advanced machine is larger and has higher initial firing (i.e., combustion) temperatures than conventional turbines. This results in a larger, more thermally efficient machine. For example, the electrical generating capability of the GE Frame 7FA.05 advanced machine is about 221.2 MW compared to the 70 MW to 120 MW conventional machines. The higher initial firing temperature results in about 20 percent more electrical energy produced for the same amount of fossil fuel used in conventional machines. This has the added advantage of producing lower air pollutant emissions (e.g., NO_X, PM, and CO) for each MW generated. While the increased firing temperature increases the thermal NO_X generated, this NOx increase is controlled through combustor design.

The amount of NO_X control achieved by the low-NO_X combustion technology on an advanced CT is considerably higher than that achieved by a conventional CT. Because of the higher firing initial temperatures, the advanced CT results in greater NO_X emission formation. Since the advanced machine has higher firing temperatures, the NO_X emissions without the use of low-NO_X combustion technology are much higher than a conventional CT (greater than 180 ppmvd vs. 150 ppmvd). This results in an overall greater NOx reduction on the advanced CT.

The second unique attribute of the advanced machine is the use of low-NO_X combustors that will reduce NO_X emissions to 9 ppmvd when firing natural gas. Thermal NO_X formation is inhibited by using staged combustion techniques where the natural gas and combustion air are premixed prior to ignition. This level of control will result in NO_X emissions of about 0.033 lb/10^6 Btu when firing gas, which is more than 10 times lower than the existing 36 GTs the Project is replacing.

Since the purpose of the Project is to replace first-generation simple cycle units, it is appropriate to compare the proposed emissions on an equivalent generation basis to that of a conventional CT. The existing gas turbines at the FPL Fort Myers Plant are early combustion turbines. The heat rates for these GTs are in the range of 15,000 Btu/kWh or higher. In contrast, the Project will have CTs that have heat rates in the range of 10,000 to 11,000 Btu/kWh at base load conditions. The NO_X emission rates will not only be more than 10 times lower on a heat input basis but more than 15 times lower on a generation basis (i.e., lb NO_X /MWh basis)

Proposed BACT and Rationale

The proposed BACT for the Project is advanced low-NO_X combustion technology. EPA updated the NSPS for Stationary Combustion Turbines that will commence construction after February 18, 2005. The Subpart KKKK emissions requirements applicable to combustion turbines greater than 30 MW apply to CTs associated with the Project. The NO_x emissions are limited to 15 ppm corrected to 15 percent O_2 or 0.43 lb/MW-hr for natural gas firing and 42 ppm corrected to 15 percent O_2 or 1.3 lb/MW-hr for ULSD oil firing. For the Project, the NO_x emissions are limited to 9 ppm corrected to 15 percent O_2 and about 0.33 lb/MW-hr or less when natural gas firing under base load conditions. NO_X from oil firing will be controlled using water injection (42 ppmvd corrected to 15 percent oxygen). This combination of control technologies is proposed for the following reasons:

1. SCR was rejected based on technical, economic, environmental, and energy grounds.
2. The estimated incremental cost of SCR is approximately at over $20,000 per ton of NO_X removed and is similar to cost for other Projects that have rejected SCR as being unreasonable. This is even more apparent if additional pollutant emissions due to SCR are considered.
3. Additional environmental impacts would result from SCR operation, including emissions of ammonia; from secondary emissions (to replace the lost generation); and from the generation of hazardous waste (i.e., spent catalyst). While NO_X emissions would be reduced by about 150 TPY per unit with SCR, the net emissions reduction associated with the entire Project would not be as great. There are three additional factors that must be considered:
    a. The Project replaces 36 less efficient and higher emitting GTs with low stack heights that have concomitantly higher air quality impacts. Emissions are reduced by over a factor of 10 on a heat input basis and by over a factor of 15 on a generation basis.
    b. SCR will increase direct emissions. Ammonia slip would occur, and it may be as high as 46.7 TPY per unit. Additional particulate matter may be formed through the reaction of ammonia and sulfur oxides forming ammonium salts. As much as 6.4 TPY per unit additional particulate matter may be formed.
    c. SCR will require energy for system operation and reduce the efficiency of the combustion turbine. This lost energy would have to be replaced because the Project would be an efficient peaking power plant while operating. Any peaking power plants replacing this lost energy would be lower on the dispatch list and inevitably more polluting. Conservatively, this lost energy would result in the emissions of an additional 8.56 TPY of criteria pollutants. Additional emissions of carbon dioxide would also result.
4. The energy impacts of SCR will reduce potential electrical power generation by more than 5 million kilowatt hours (kWh) per year. This amount of energy is sufficient to provide the monthly electrical needs of 419 residential customers.

5. The proposed BACT (i.e., low-NO_x combustion technology) provides the most cost effective control alternative, is pollution preventing, and results in low environmental impacts (less than the significant impact levels). Low-NO_x combustion technology at the proposed emissions levels has been adopted previously in BACT determinations. Indeed, compared to existing GTs the Project is replacing, the use of the CTs associated with the Project will result in over 15 times less NO_x emission while producing the same amount of electricity.

Carbon Monoxide and Volatile Organic Compounds

The FDEP has historically established simple cycle CT BACT emission rates based on the use of good combustion practices for minimizing CO and VOC emissions, as add-on CO/VOC controls have been determined to be cost prohibitive. Similarly, CO/VOC add-on controls for the Project have been determined to not be cost effective and BACT is based on good combustion practices.

A review of the most recent BACT determinations for CO for large frame simple-cycle CT projects is provided in Tables D-3 and D-4. Table D-3 demonstrates that FDEP has historically established CT BACT emission rates based on the use of good combustion practices for minimizing CO emissions for simple cycle frame turbines. Although the Department has permitted GE7FA.03 and GE7FA.04 CT models with CO BACT levels as low as 4.1 ppmvd natural gas firing and 8 ppmvd for ULSD oil firing based on operational data, the Project may utilize new GE model 7FA.05 or Siemens F5 turbines for which no operational data exists. The design of the new 7FA.05 differs from the 7FA.03 and 7FA.04 in that power generation has been increased by approximately 20% to over 200 MW at ISO conditions, through higher firing temperature and optimization. The new CT design yields uncertainty that the CO concentrations will be similar to the previous 7FA models. While other BACT determinations have established permit limits as low as 4.1 ppmvd, it has been through supporting operational data of their existing fleet of similar turbines. Because historical operating data are not available for the 7FA.05 and Siemens F5 units, vendor guarantees should be used to establish the BACT limits.

Feasible Controls

The feasible control technologies, in the order of highest to lowest control efficiency, for simple cycle CTs are as follows:

- Oxidation catalytic reduction (approximately 80% control efficiency)
- Good Combustion Practice including the air-to-fuel ratio and the staging of combustion

Technology Description

Emissions of CO are dependent upon the combustion design, which is a result of the manufacturer's operating specifications, including the air-to-fuel ratio, staging of combustion, and the amount of water injected (i.e., for oil firing). The CTs proposed for the Project have designs to optimize combustion efficiency and minimize CO emissions; however as previously indicated, the GE model 7FA.05 turbines are new CTs with no existing in-service CO test data. Catalytic oxidation is a post-combustion control that has been employed in CO nonattainment areas where regulations have required CO emission levels to be less than those associated with combustion controls alone.

The "Top Down" BACT analysis was performed for the following alternatives:

- Oxidation catalyst at approximately 80 percent removal, resulting in CO concentrations of approximately 2 ppmvd
- Combustion controls at 9 ppmvd when firing natural gas (at base load) and 20 ppmvd when firing oil (at base load)

In an oxidation catalyst control system, CO emissions are reduced by allowing unburned CO to react with oxygen at the surface of a precious metal catalyst, such as platinum. Combustion of CO starts at about 300°F, with an efficiency of 90 percent occurring at temperatures above 600°F. Catalytic oxidation occurs at temperatures 50 percent lower than that of thermal oxidation, which reduces the amount of thermal energy required. For CTs, the oxidation catalyst can be located directly after the CT. Catalyst size depends upon the exhaust flow, temperature, and desired efficiency.

Impact Analysis

Tables 4-5a, 4-5b, 4-6a, and 4-6b present the capital and annualized costs for the GE and Siemens CTs for CO oxidation catalysts. These tables assume total hours per year of operation of 3,390, of which 500 hours is with operation on oil firing. The following summarizes the CO oxidation catalyst cost effectiveness for these scenarios:

- GE 7FA.05 -- CO Oxidation Catalyst Cost Effectiveness – 53.3 CO TPY Reduction; $581,744 per year per CT = $11,744 per ton CO reduced
- Siemens -- CO Oxidation Catalyst Cost Effectiveness – 24.6 CO TPY Reduction; $589,593 per year per CT = $28,297 per ton CO reduced

Economic - The capital and annualized cost of a CO oxidation catalyst are approximately $2,100,000 and $600,000 per unit, respectively, corresponding to the most cost effective scenario. The resulting cost effectiveness is greater than $10,000 per ton of CO removed. The cost effectiveness is based on 2,890 hr/yr on natural gas and 500 hours per year of operation on ULSD oil. No costs are associated with combustion techniques since they are inherent in the design. In addition, actual CO emissions are likely to be less than the GE guarantee rates of 9 ppmvd and 20 ppmvd (for gas and oil, respectively) and as a result the cost effectiveness based on actual emissions would be higher than $11,000 per ton of CO removed. Detail calculations are provided in Tables 4-5a, 4-6a, 4-5b, and 4-6b.

Environmental - The air quality impacts of both oxidation catalyst control and combustion design control techniques are below the significant impact levels for CO. Therefore, no significant environmental benefit would be realized by the installation of a CO catalyst. Moreover, the air quality impacts at the proposed CT emission rate are predicted to be much less than the PSD significant impact levels. The maximum CO impacts are less than 3 percent of the applicable ambient air quality standards. There would also be no secondary benefits, such as reductions in acidic deposition, to reducing CO.

Energy - An energy penalty would result from the pressure drop across the catalyst bed. A pressure drop of about 2 inches water gauge would be expected. At a catalyst back pressure of about 2 inches, an energy penalty of about 1,560,000 kWh/yr would result at 100 percent load, based on the worst case scenario. This energy penalty is sufficient to supply the electrical needs of about 130 residential customers for a year. To replace this lost energy, about 1.6×10^{10} Btu/yr or about 16 million ft^3/yr of natural gas would be required.

Proposed BACT and Rationale

Combustion design is proposed as BACT, as there are adverse technical and economic consequences of using catalytic oxidation on CTs. The proposed BACT emission limits for CO are 9 ppmvd when firing natural gas and 20 ppmvd when firing distillate oil at base load conditions. Catalytic oxidation is considered unreasonable for the following reasons:

- Catalytic oxidation will not produce measurable reduction in the air quality impacts
- The economic impacts are significant (i.e., the capital cost is about $2.1 million per unit, with an annualized cost of approximately $600,000 per year per unit)

No existing operational data exists for the new GE 7FA.05 or Siemens F5 turbines necessary to justify CO concentrations less than the vender guarantee. Combustion design is proposed as BACT as a result of the technical and economic consequences of using catalytic oxidation on CTs. Catalytic oxidation is considered unreasonable since it will not produce a measurable reduction in the air quality impacts. The cost of an oxidation catalyst would be significant and not be cost effective given the maximum proposed emission limits, and even less so if actual emissions are less than the value that are guaranteed.

$PM/PM_{10}/PM_{2.5}$

The $PM/PM_{10}/PM_{2.5}$ emissions from the CTs are a result of incomplete combustion and trace elements in the fuel. The design of the CT ensures that particulate emissions will be minimized by combustion controls and the use of clean fuels. A review of EPA's BACT/LAER Clearinghouse Documents did not reveal any post-combustion particulate control technologies being used on gas-fired or oil-fired CTs.

The use of clean fuels, characterized by low PM and trace contaminant contents and advanced combustion techniques, results in negligible PM and PM_{10} emissions. Emission limits based on the use of clean fuels (i.e., natural gas and ULSD oil) have been established as BACT for PM/PM_{10} emissions in previous PSD permits.

The maximum particulate emissions from the CT will be lower in concentration than that normally specified for fabric filter designs {i.e., the grain loading associated with the maximum particulate emissions is less than 0.01 grain per standard cubic foot (gr/scf), which is a typical design specification for a baghouse. This further demonstrates that no further particulate controls are necessary for the project.

There are no technically feasible methods for controlling the $PM/PM_{10}/PM_{2.5}$ emissions from CTs, other than the inherent quality of the fuel. Clean fuels, natural gas and distillate oil represent BACT for $PM/PM_{10}/PM_{2.5}$ emissions.

4.2.2 Emergency Black-Start Generators

The emergency black-start generators proposed for the Project will utilize clean fuel (i.e., ULSD oil) and good combustion techniques to minimize emissions. The black start emergency generators will be subject to the requirements of 40 CFR 60 Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, published July 11, 2006 and effective on September 11, 2006. For the Project, these units meet the definition of "emergency stationary internal combustion engine" in the NSPS. FPL is proposing to comply with the applicable requirement of 40 CFR Part IIII for these compression ignition engines as BACT for the generators and they would be operated in accordance with Section 60.4211(f).

5.0 AMBIENT MONITORING ANALYSIS

Based on the net emission changes from the proposed Project (see Table 3-3), pre-construction ambient monitoring analyses for PM_{10}, $PM_{2.5}$, NO_2, CO, and O_3 (based on NO_X or VOC emissions) may be required as part of the PSD application. Ambient monitoring analyses are not required if it can be demonstrated that the Project's maximum air quality impacts will not exceed the PSD significant monitoring concentrations (SMC) and, for O_3, the Project's potential emissions will not exceed 100 TPY of NO_X or VOC emissions.

Maximum impacts due to the Project only are predicted to be below the SMC for PM_{10}, $PM_{2.5}$, NO_2, and CO (see Table 6-7 and 6-8). As a result, a pre-construction ambient monitoring analysis is not required for these pollutants as part of the application, except for $PM_{2.5}$ due to a recent ruling by the US Court of Appeals (see the following paragraphs). It should be noted that EPA has not proposed SMC for the 1-hour average NO_2 concentration.

For O_3, the Project's VOC emissions are less than 100 TPY; however, NO_X emissions are more than 100 TPY or more, which requires that pre-construction ambient monitoring analysis for O_3 be submitted as part of the application.

For $PM_{2.5}$, on January 22, 2013, the US Court of Appeals vacated the parts of the two PSD rules (40 CFR 51.166 and 40 CFR 52.21) establishing an SMC, finding that EPA was precluded from using the $PM_{2.5}$ SMC to exempt permit applicants from the statutory requirement to compile preconstruction monitoring data. As a result, permitting of new or modified sources requires submittal of monitoring data prior to construction regardless of the source's impact. As a result, $PM_{2.5}$ concentrations from a representative monitor must be submitted as part of the PSD permit application because the Project's $PM_{2.5}$ emissions are greater than the SER.

Based on the impacts of PM_{10}, NO_2, and CO being less than SMC, an exemption from the pre-construction monitoring requirement is applicable pursuant to Rule 62-212.400(3)(e), F.A.C. In addition, ambient O_3 and $PM_{2.5}$ monitoring data collected by FDEP at monitoring stations near the Project are considered to be representative of air quality in the Project's vicinity. These data are being used to satisfy the pre-construction monitoring requirement for O_3 and $PM_{2.5}$ that primarily form from atmospheric processes and are not directly emitted.

Air quality monitoring data collected in Lee County from 2010 through 2012 for O_3 and $PM_{2.5}$ are presented in Tables 5-1 and 5-2, respectively. These data indicate that the maximum air quality concentrations measured in the region are well below applicable standards.

Since the Project's maximum 1-hour average NO_2 impacts are predicted to be greater than the significant impact levels for these pollutants (see Table 6-8, Section 6.1, 1-Hr NO_2 NAAQS Results), more detail analyses are required to demonstrate compliance with the AAQS. For these analyses, total air quality impacts are predicted for the modeled sources which are added to a non-modeled background concentration. The non-modeled background concentrations are estimated from representative ambient air quality monitoring data obtained from air monitoring stations. The 1-hour NO_2 monitoring data collected at monitor ID 012-115-1006 in Sarasota, Florida, which is the nearest NO_2 monitor to the Fort Myers plant is summarized in Table 5-3.

6.0 AIR QUALITY IMPACT ANALYSIS

This section addresses the predicted air quality impacts of regulated air pollutants due to the Project and, as appropriate, background sources. The general modeling approach followed the latest EPA and FDEP modeling guidelines for predicting air quality impacts for regulated pollutants.

As described in Section 1.0, the Project replaces 12 GTs located at the Fort Myers plant in Lee County. These existing units consist of two aero-derivative gas turbines coupled with a single gas flow driven turbine-electric generator that have low stack heights (less than 50 feet) and high NO_X emissions rates. The low stack heights in proximity to nearby property boundaries result in decreased dispersion properties and, when combined with high NO_X emission rates, result in elevated concentrations of NO_2 concentrations. A 1-hour average NAAQS, was recently promulgated by EPA and adopted by FDEP, which is much more stringent than the annual average NAAQS for NO_2. Preliminary modeling analyses of these 12 GT units found that the NO_X emissions from these units would not disperse sufficiently to bring off-site NO_2 concentrations below the 1-hour NO_2 NAAQS. FPL's evaluation concluded that the most cost effective solution is to replace the existing GTs with new, highly efficient combustion turbines with low NO_X emissions. After consultations and agreement with FDEP, FPL plans to bring three new CTs into service by December 31, 2016. The modeling presented in this report provides the impact analysis that would assure 1-hour NO_2 concentrations in the vicinity of the Project do not exceed the NAAQS.

While 12 GTs will be retired at the Fort Myers Plant as a result of the Project, this air quality impact assessment only considered the increase in emissions from the three new CTs and does not address the improvement in the air quality from the retirement of the existing GTs. As a result, the analysis results will conservatively reflect the air quality impact due to the overall Projects net emissions increase without consideration of the air quality improvements made by retiring the existing GTs. This air quality improvement would occur both in the vicinity of the Project site and at the ENP and result in the expansion of the PSD Increments in the Class II areas in the Project's vicinity and at the ENP PSD Class I area.

Based on the comparison of baseline actual emissions from the existing 12 GTs and potential emissions of the Project, the net emissions increases of the Project are greater than the PSD SERs for NO_X, $PM/PM_{10}/PM_{2.5}$, and CO requiring an air quality impact analysis for these pollutants under FDEP rules.

The following sections present a summary of the air quality modeling methodology used for the air quality impact analyses for the proposed Project.

6.1 Air Modeling Analysis Approach and Results – PSD Class II Areas

Model Selection

The selection of air quality models to calculate air quality impacts for the proposed project must be based on the models' ability to simulate impacts in the vicinity of the facility. The American Meteorological Society and EPA Regulatory Model (AERMOD) dispersion model was used to evaluate the pollutant impacts due to the proposed project. AERMOD (Version 12345) is available on the EPA's Internet web site, Support Center for Regulatory Air Models (SCRAM), within the Technology Transfer Network (TTN). The EPA and FDEP recommend that AERMOD be used to predict pollutant concentrations at receptors located within 50 km of a source. AERMOD calculates hourly concentrations based on hourly meteorological data. AERMOD is applicable for the type of Project sources and area in which the Project is located since it is recognized as containing the latest scientific algorithms for simulating plume behavior in all types of terrain.

AERMOD was used to predict the maximum pollutant concentrations due to the Project at nearby areas surrounding the facility.

For modeling analyses that will undergo regulatory review, such as determining compliance with NAAQS, the following model features are recommended by EPA for rural mode and are referred to as the regulatory default options in AERMOD:

1. Final plume rise at all receptor locations
2. Stack tip downwash
3. Buoyancy induced dispersion
4. Default wind speed profile coefficients for rural mode
5. Default vertical potential temperature gradients
6. Calm wind processing

The EPA regulatory default options were used to address maximum impacts

Project Sources

Air quality analyses were performed to assess the maximum impacts of the three new simple-cycle CTs at FPL's existing Fort Myers Plant. The CTs being evaluated for the Project are nominal 200 MW units and include the GE 7FA.05 and 7FA.04 CTs, and Siemens F(5) CTs (or their equivalents).

The air modeling analyses address air impacts from the GE 7FA.05 and Siemens F5 CTs. Because the GE 7FA.04 CT has lower emissions and slightly lower exit gas temperatures and flow rates over the range of turbine inlet temperatures and loads than those of the GE 7FA.05, the predicted air quality impacts for the GE 7FA.05 CTs are expected to be higher than those for the GE 7FA.04 CT and therefore provide a conservative estimate of the impacts of the GE 7FA.04 CTs.

Summaries of the criteria pollutant emission rates, physical stack and stack operating parameters for the proposed GE 7FA.05 and Siemens F5 CTs used in the air modeling analysis are presented in Section 2 for both natural gas-firing and ULSD oil-firing. For each CT type, impacts were predicted for a range of possible operating conditions. The following 9 CT load and temperature scenarios were evaluated for the GE 7FA.05 CTs when firing natural gas and ULSD oil:

- 100 percent load and ambient temperatures of 35°F, 75°F, and 95°F
- 75 percent load and ambient temperature of 35°F, 75°F, and 95°F
- 50 percent load and ambient temperature of 35°F, 75°F, and 95°F

For Siemens F5 CTs firing natural gas, the following 6 operating scenarios were evaluated in the modeling analysis:

- 100 percent load and ambient temperatures of 35°F, 75°F and 95°F
- 40 percent load and ambient temperature of 35°F and 75°F
- 44 percent load and ambient temperature of 95°F

For Siemens F5 CTs firing ULSD oil, the following 6 operating scenarios were evaluated in the modeling analysis:

- 100 percent load and ambient temperatures of 35°F, 75°F and 95°F
- 50 percent load and ambient temperature of 35°F 75°F and 95°F

The new CTs will have stack heights of 100.5 feet and an inner diameter of 23 feet. Building downwash effects were included in the modeling analysis to account for the nearby structures. In addition, for cumulative source impact assessments, building downwash effects were included in the modeling analysis for the Fort Myers Plant's existing sources.

The Project also includes four black-start engines (or two existing GTs) which will be used on an emergency basis only to start the new CTs. Operation of this equipment is limited to no more than 100 hr/yr for non-emergency situations. These engines are considered intermittent sources based on guidance from the EPA memo "Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-Hour NO_2 National Ambient Air Quality Standard (March 1, 2011)". From that guidance, compliance demonstrations should be based on emissions that are continuous or frequent enough to contribute significantly to the annual distribution of daily maximum 1-hour concentrations.

In accordance with this guidance and the recommendations in Section 8.1.1 of Appendix W (40 CFR 51), FDEP was contacted with regards to the operation of the proposed black-start engines and agreed that these engines were intermittent sources. Based on the planned intermittent use of the black-start engines, the emissions from these equipment were not modeled in the air impact assessment.

Building Downwash Effects

The dimensions of structures associated with the CTs were provided by the vendors of each type of CT. The primary structures for the CTs are the air inlet structures and the dimensions for each structure are provided in the table below. All structures were processed in the EPA Building Profile Input Program [(BPIP), Version 04274] to determine direction specific structure heights and widths for each 10 degree azimuth direction for each source that was included in the modeling analysis:

Structure	Height (ft)	Width (ft)	Length (ft)
For GE F7A.05 CTs			
CT Air Inlet	72.1	21.4	44.3
CT Building	22	36	30
For Siemens F5 CTs			
CT Air Inlet	75	21.4	44.3
CT Building	22	36	30

Meteorological Data

Meteorological data used in AERMOD to estimate air quality impacts consisted of a concurrent 5-year period of hourly surface weather observations and upper air sounding data collected from the National Weather Service (NWS) stations located at the Fort Myers Page Field Airport (FMY) and Ruskin, respectively. The 5-year period of the meteorological data was from 2006 through 2010 and was prepared by the FDEP using AERMET Version 12345. AERMINUTE Version 11059 was used to process 1-minute wind data collected by the automatic surface observing system (ASOS) into hourly averages of wind direction and wind speed. A minimum wind speed threshold of 0.5 meters per second (m/s) was used. The NWS office at the airport is located approximately 14 km (8.5 miles) southwest of the Project site. The areas between the airport and the Fort Myers Plant are flat with very similar land characteristics.

Land use parameters were extracted seasonally and for twelve 30-degree wind direction sectors using AERSURFACE Version 13016. The parameters were taken from the airport (measurement site). The annual average land use parameters for both the airport and application site locations are as follows:

Location	Albedo	Bowen Ratio	Surface Roughness
NWS Station	0.16	0.60	0.093
Project Site	0.15	0.45	0.068

The results indicate that the Project site's land use parameters are similar to those for the NWS station. As such, the meteorological data with land use values from the NWS site were selected to be used throughout the modeling analysis.

Receptor Locations

A Cartesian grid was used to predict concentrations on and beyond the property boundary out to 5 km. Receptors were located at the following intervals and distances from the Project:

- Along the property boundary or fence line – 50 meters
- Beyond the fence line to 2 km – 100 meters
- From 2 km to 5 km – 250 meters

More than 2000 receptors were used to estimate the maximum concentrations predicted for the Project.

Significant Impact Analysis

A significant impact analysis is performed to determine the maximum air quality impact due to only the Project's emissions increases. If the highest predicted impact for a particular pollutant and averaging time exceeds the respective PSD Class II significant impact level (SIL), more detailed modeling analyses are required for that pollutant and averaging time to address compliance with the NAAQS and, if applicable, the allowable PSD increment.

For this Project, SIL analyses were performed for the following pollutants and averaging times:

- NO_2: 1-hour and annual averages
- PM_{10}: 24-hour and annual averages

- $PM_{2.5}$: 24-hour and annual averages
- CO: 1-hour and 8-hour averages

The SIL analyses for the 1-hour SO_2, 1-hour NO_2, and 24-hour and annual $PM_{2.5}$ concentrations are based on the maximum 5-year average concentrations predicted using 5 years of representative meteorological data. The SIL analyses for the 24-hour PM_{10} and 1-hour and 8-hour CO concentrations are based on the maximum predicted concentrations over the 5-year period. The SIL analyses for the annual average NO_2 and PM_{10} concentrations are based on maximum predicted concentrations for any year over the 5-year period.

The predicted annual average impacts for the significant impact analysis are based on the CTs being limited to 3,390 hr/yr with ULSD oil-firing for each CT limited to 500 hr/yr. For pollutants with higher predicted impacts occurring when firing ULSD oil, the predicted annual impact is based on the maximum of 500 hr/yr of ULSD oil-firing. The short-term impacts are based on an operation of 10 hours per day of ULSD oil firing that conservatively represents operation of the CTs on this fuel. For pollutants with higher predicted impacts occurring when firing natural gas, the predicted annual impact assumes 3,390 hr/yr of natural gas-firing and the short-term impacts assume only natural gas firing.

Once the highest impacts were identified for the combination of ambient temperature and operating load condition (i.e., worst-case operating condition), subsequent analyses were performed with the emissions rates and exit gas operating data for those conditions for each pollutant and CT vendor.

It should be noted that In January 2013, the $PM_{2.5}$ SIL under 40 CFR 51.166(k)(2) and 40 CFR 52.21(k)(2) were vacated and remanded the portions of EPA's rule regarding the SIL to exempt sources from cumulative source modeling [Sierra Club v. EPA, 705 F.3d 458 (D.C. Circuit 2013)]. On March 4, 2013, EPA issued *Draft Guidance for $PM_{2.5}$ Permit Modeling* (Stephen D. Page, Director, OAQPS) that provided preliminary recommendations describing how a stationary source seeking a PSD permit can demonstrate that it will not cause or contribute to a violation of the NAAQS and PSD increments. According to the EPA's draft guidance, with additional justification, the permitting authority may use the same $PM_{2.5}$ SILs that were vacated to demonstrate that a full cumulative source impact analysis is not needed.

Based on the results of the significant impact analysis, only the 1-hour NO_2 concentrations were predicted to exceed the SIL. When addressing the NAAQS for 1-hour NO_2, the 5-year averages of the 98^{th} (8^{th} highest) percentile of the daily maximum 1-hour average concentrations at each receptor were determined. The maximum 5-year average of these values is used to estimate the maximum impact.

NO_2 Modeling Analysis

A 3-tiers modeling approach based on the EPA modeling guidance document (Tyler Fox, March 1, 2011; Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard), a 3-tiered modeling approach is recommended for modeling NO_2 concentrations. These approaches are:

- Tier 1: NO_X emissions are assumed fully converted to NO_2
- Tier 2: NO_X emission are assumed 75 percent converted to NO_2 on an annual basis and 80 percent converted on a 1-hour basis
- Tier 3: an application of a more detailed modeling approach such as Plume Volume Molar Ratio Method (PVMRM) or the Ozone Limited Method (OLM) to further refine NO_2 impacts

For this analysis, a Tier 2 modeling approach was used to predict NO_2 concentrations.

Cumulative Air Quality Analyses

Background concentrations are necessary to determine total ambient air quality impacts to demonstrate compliance with the NAAQS. "Background concentrations" are defined as concentrations due to sources other than those specifically included in the modeling analysis. For all pollutants, background would include other point sources not included in the modeling, fugitive emission sources, and natural background sources. In general, monitoring data collected near the area in which the air quality impact is performed is used for this purpose.

Concentrations predicted for the NAAQS analyses include the modeled impacts from sources at the facility, background emission sources in the vicinity of the Fort Myers Plant, and a background concentration that accounts for sources not included in the modeling analysis.

Background NO_2 Emission Sources

Current EPA guidance on 1-hour NO2 NAAQS is provided in the EPA memorandum (Tyler Fox, March 1, 2011, see above). The memorandum suggests that background sources within a radius of 10 km are sufficient for addressing any potential source interactions that could occur during a 1-hour averaging time.

Based on the results of the significant impact analysis, an inventory of background NO_2 emission sources was requested from FDEP. A summary of the emissions, distances and directions of these sources from the proposed project are summarized in Table 6-1. A detailed list of background sources included in the NAAQS modeling analysis is summarized in Table 6-2.

Non-Modeled Background Concentrations

Summaries of measured ambient concentrations, for use in determining background concentrations, are presented in Section 5.0. The background concentrations are based on averages of monitor measurements from 2010 to 2012. The background concentrations used for the 1-hour NO_2 NAAQS modeling analysis is 35.7 μg/m^3.

Model Results

Significant Impact/CT Load Analysis – GE 7FA CTs

The results of the CT load analysis for one CT firing natural gas is presented in Table 6-3a and Table 6-3b presents the CT load analysis results for one CT firing ULSD oil. The predicted maximum project-only impacts due to the three CTs are compared to the significant impact levels in Table 6-5, which presents results for both natural gas and ULSD oil firing. Based on the results presented in Table 6-5, the proposed project's maximum impacts are predicted to be less than the SIL except for the 1-hour NO_2 concentrations. As such, a cumulative source modeling analysis is required to determine compliance with the 1-hour NO_2 NAAQS.

Significant Impact/CT Load Analysis – Siemens F5 CTs

The results of the CT load analysis for one CT firing natural gas is presented in Table 6-4a and Table 6-4b presents the CT load analysis results for one CT firing ULSD oil. The predicted maximum project-only impacts due to three CTs are compared to the significant impact levels in Table 6-6, which presents conservative results for both natural gas and ULSD oil firing. Based on the results presented in Table 6-6, the proposed project's maximum impact are less than the SIL except for 1-hour NO_2. As such, a cumulative source modeling analysis was conducted to determine compliance with the 1-hour NO_2 NAAQS.

1-hour NO_2 NAAQS Results

The NAAQS modeling results are summarized in Table 6-7. With either Siemens or GE CTs, the maximum predicted 1-hour NO_2 concentration due to all sources is 45.9 μg/m^3, which when added to the background concentration, results in a total concentration of 81.6 μg/m^3, which is well below the NAAQS of 188.1 μg/m^3.

6.2 Air Modeling Analysis Approach and Results- PSD Class I Area

Model Selection and General Assumptions

The CALPUFF air modeling system (Version 5.8) was used to predict the Project's maximum air quality concentrations at locations beyond 50 km from the Project. CALPUFF is a non-steady state Lagrangian puff long-range transport model that includes algorithms for chemical transformations (important for visibility controlling pollutants) and wet/dry deposition. CALPUFF was used in a manner that is consistent with methodologies recommended in the following document and in subsequent discussions with the FLM.

- FLMs' AQRV Workgroup (FLAG) guidance document, revised in October 2010 and referred to as the FLAG Phase I Report

Parameter settings to be used in CALPUFF were based on the latest regulatory guidance. Where the modeling guidance recommends regulatory model defaults, those defaults were used. For ozone background concentrations, observed hourly ozone data for 2001 to 2003 from CASTNET and AIRS stations was used. A fixed monthly ammonia background concentration of 0.5 ppb was used. For predicting 24-hour visibility impairment, the FLAG guidance recommends using CALPOST Version 6.221, Method 8 (MVISBK = 8) and submode 5 (M8_MODE = 5). For this analysis, the background hygroscopic and non-hygroscopic aerosol levels were derived from the 20 percent best natural background days. In addition, parameters were set to calculate wet and dry (i.e., total) fluxes and concentrations at the evaluated PSD Class I area.

Project Modeled Emissions

The Project's emission, stack, and operating data as well as building dimensions were modeled for the emission sources as indicated previously.

PM emissions for the Project's stack emissions were speciated into six particle size categories for modeling. All of the condensable PM emissions, which were assumed to be 50-percent of the total stack emissions were evenly split into two smallest size categories – 0 to 0.625 microns and 0.625 to 1 micron. The filterable PM emissions, which were assumed to be 50-percent of the total PM emissions were evenly split into 4 particle size categories – 0 to 0.625, 0.625 to 1, 1 to 1.25, and 1.25 to 2.5 microns. Therefore, all of the PM_{10} emissions were assumed equal to $PM_{2.5}$ emissions. Results of the individual size categories were grouped to obtain total $PM_{10}/PM_{2.5}$ impact.

Note that emissions for sulfuric acid mist were input directly into CALPUFF as SO_4.

Building Downwash Considerations

The same methods used in the PSD Class II analyses to assess building downwash were used in these analyses.

Meteorological Data

The far-field air modeling analyses were conducted using meteorological and geophysical databases which have been developed for use with the most recent versions of CALPUFF. These datasets were developed using CALMET Version 5.8 and were originally developed by VISTAS and recompiled for Version 5.8 by the FLM. The dataset have 4-km spacing and cover the period from 2001 to 2003. For this Project, meteorological data from VISTAS subdomain No. 2 were used for the far-field modeling analysis.

Receptor Locations

The FLM has developed receptors to represent the boundary and internal areas of all PSD Class I areas. The Class I analysis used the receptors developed by the FLM for ENP.

Significant Impact Analysis

Significant impact analyses were performed to assess the Project's impacts at the PSD Class I area. The maximum predicted NO_2, PM_{10}, and $PM_{2.5}$ concentrations due to the Project were compared to EPA's proposed PSD Class I significant impact levels. If the Project's impacts exceed the proposed EPA PSD Class I significant impact levels, then a more detailed PSD Class I increment analysis will be performed on a pollutant-specific basis. In the PSD Class I incremental analysis, PSD-increment affecting sources will be modeled for comparison to the allowable PSD Class I increments.

The proposed PSD Class I significant impact levels are:

- NO_2: annual average – 0.1 µg/m^3
- PM_{10}: 24-hour – 0.3 µg/m^3, and annual average – 0.2 µg/m^3
- $PM_{2.5}$: 24-hour – 0.07 µg/m^3, and annual average – 0.06 µg/m^3

Model Results

The results of the PSD Class I significant impact analysis for the ENP is presented in Table 6-8. The analysis results indicated that the proposed project's maximum predicted impacts will be less than the Class I SIL and that further analyses to determine compliance with the allowable PSD Class I increments are not required.

7.0 ADDITIONAL IMPACT ANALYSIS

This section presents the impacts that the Project and general commercial, residential, industrial and other growth associated with the Project will have on vegetation, soils, and visibility in the vicinity of the site and impacts at the PSD Class I area of the ENP related to AQRVs. Specifically, this section addresses FDEP Rules 62-212.400(4)(e), (8)(a) and (b), and (9), F.A.C. These rules are:

> (4) Source Information.
>
> (e) The air quality impacts, and the nature and extent of any or all general commercial, residential, industrial, and other growth which has occurred since August 7, 1977, in the area the source or modification would affect.
>
> (8) Additional Impact Analyses.
>
> (a) The owner or operator shall provide an analysis of the impairment to visibility, soils and vegetation that would occur as a result of the source or modification and general commercial, residential, industrial and other growth associated with the source or modification. The owner or operator need not provide an analysis of the impact on vegetation having no significant commercial or recreational value.
>
> (b) The owner or operator shall provide an analysis of the air quality impact projected for the area as a result of general commercial, residential, industrial and other growth associated with the source or modification.
>
> (9) Sources Impacting Federal Class I Areas. Sources impacting Federal Class I areas are subject to the additional requirements provided in 40 CFR 52.21(p), adopted by reference in Rule 62-204.800, F.A.C.

7.1 Potential Impacts Due to Associated Growth

7.1.1 Impacts of Associated Growth

As previously discussed, the Project will replace the 12 existing GTs located at the Fort Myers Plant. These existing GTs have a capacity of about 500 MW and will be replaced with three highly efficient lower emitting CTs with a nominal capacity of 200 MW each, for a total of only 1,000 MW. Thus, the Project is not in response to growth and will provide significant air quality improvement when compared to the existing GTs.

Construction of the proposed Project will occur over approximately 18 to 24 months and will require an average of over 100 workers during that time. It is anticipated that many of these construction personnel will commute to the site. However, no additional permanent workers will be employed for the operation of the facility. The workforce needed to construct and operate the facility represents a small fraction of the population already present in the immediate area. Therefore, while there would be a small increase in vehicular traffic in the area, the effect on air quality levels would be minimal.

There are also expected to be no air quality impacts due to associated commercial and industrial growth. The existing commercial and industrial infrastructure is adequate to provide any support services that facility might require and would not increase with the operation of the facility.

As demonstrated in Section 6.0, the maximum air quality impacts resulting from the proposed new CT Project are predicted to be low and below the significant impact levels for all by the 1-hour NO2 concentrations. The predicted cumulative source 1-hour NO2 impacts demonstrate that the Fort Myers Plant and background sources will comply with the NAAQS. In fact, the retirement of 12 GTs at the existing Fort Myers Plant is expected to significantly improve air quality in the area.

7.2 Potential Air Quality Effect Levels on Soils, Vegetation and Wildlife

7.2.1 Soils

The potential and hypothesized effects of atmospheric deposition on soils include:

- Increased soil acidification
- Alteration in cation exchange
- Loss of base cations
- Mobilization of trace metals

The potential sensitivity of specific soils to atmospheric inputs is related to two factors. First, the physical ability of a soil to conduct water vertically through the soil profile is important in influencing the interaction with deposition. Second, the ability of the soil to resist chemical changes, as measured in terms of pH and soil cation exchange capacity (CEC), is important in determining how a soil responds to atmospheric inputs.

7.2.2 Vegetation

The concentrations of the pollutants, duration of exposure, and frequency of exposure influence the response of vegetation to atmospheric pollutants. The pattern of pollutant exposure expected from the facility is that of a few episodes of relatively high ground-level concentration, which occur during certain meteorological conditions, interspersed with long periods of extremely low ground-level concentrations. If there are any effects of stack emissions on plants, they will be from the short-term, higher doses. A dose is the product of the concentration of the pollutant and duration of the exposure.

In general, the effects of air pollutants on vegetation occur primarily from SO_2, NO_2, O_3, and PM. Effects from minor air contaminants, such as fluoride, chlorine, hydrogen chloride, ethylene, ammonia, hydrogen sulfide, CO, and pesticides, have also been reported in the literature. The effects of air pollutants are dependent both on the concentration of the contaminant and the duration of the exposure. The term "injury," as opposed to damage, is commonly used to describe all plant responses to air contaminants and will be used in the context of this analysis. Air contaminants are thought to interact primarily with plant foliage, which is considered to be the major pathway of exposure.

Injury to vegetation from exposure to various levels of air contaminants can be termed acute, physiological, or chronic. Acute injury occurs as a result of a short-term exposure to a high contaminant concentration and is typically manifested by visible injury symptoms ranging from chlorosis (discoloration) to necrosis (dead areas). Physiological or latent injury occurs as the result of a long-term exposure to contaminant concentrations below those that result in acute injury symptoms. Chronic injury results from repeated exposure to low concentrations over extended periods of time, often without any visible symptoms, but with some effect on the overall growth and productivity of the plant. In this assessment, 100 percent of the particular air pollutant in the ambient air was assumed to interact with the vegetation, which is a very conservative approach.

Nitrogen Dioxide

NO_2 can injure plant tissue with symptoms usually appearing as irregular white to brown collapsed lesions between the leaf veins and near the margins. Conversely, non-injurious levels of NO_2 can be absorbed by plants, enzymatically transformed into ammonia, and incorporated into plant constituents such as amino acids (Matsumaru, et al., 1979).

For plants that have been determined to be more sensitive to NO_2 exposure than others, acute exposure (1, 4, and 8 hours) caused 5 percent predicted foliar injury at concentrations ranging from 3,800 to 15,000 μg/m^3 (Heck and Tingey, 1979). Chronic exposure of selected plants (some considered NO_2 sensitive) to NO_2 concentrations of 2,000 to 4,000 μg/m^3 for 213 to 1,900 hours caused reductions in yield of up to 37 percent and some chlorosis (Zahn, 1975). Short-term exposure to NO_x at concentrations of 564 μg/m^3 caused adverse effects in lichen species (Holopainen and Karenlampi, 1984).

Particulate Matter

Although information pertaining to the effects of PM on plants is scarce, baseline concentrations are available (Mandoli and Dubey, 1988). Ten species of native Indian plants were exposed to levels of PM that ranged from 210 to 366 μg/m^3 for an 8-hour averaging period. Damage in the form of a higher leaf area/dry weight ratio was observed at varying degrees for most plants tested. Concentrations of PM lower than 163 µg/m^3 did not appear to be injurious to the tested plants.

Carbon Monoxide

Information pertaining to the effects of CO on plants is scarce. The main effect of high concentrations of CO is the inhibition of cytochrome *c* oxidase, the terminal oxidase in the mitochondrial electron transfer chain. Inhibition of cytochrome *c* oxidase depletes the supply of adenosine triphosphate (ATP), the principal donor of free energy required for cell functions. However, this inhibition only occurs at extremely high concentrations of CO. Pollok, et al. (1989) reported that exposure to a $CO:O_2$ ratio of 25 (equivalent to an ambient CO concentration of 6.85×10^6 µg/m^3) resulted in stomatal closure in the leaves of the sunflower (*Helianthus annuus*). Naik, et al. (1992) reported cytochrome *c* oxidase inhibition in corn, sorghum, millet, and Guinea grass at $CO:O_2$ ratios of 2.5 (equivalent to an ambient CO concentration of 6.85×10^5 µg/m^3). These plants were considered the species most sensitive to CO-induced inhibition of cytochrome *c* oxidase.

Ozone

O_3 can cause various damage to broad-leaved plants including: tissue collapse, interveinal necrosis, and markings on the upper surface leaves know as stippling (pigmented yellow, light tan, red brown, dark brown, red, or purple), flecking (silver or bleached straw white), mottling, chlorosis or bronzing, and bleaching. O_3 can also stunt plant growth and bud formation. On certain plants such as citrus, grape, and tobacco, it is common for leaves to wither and drop early.

7.2.3 Wildlife

A wide range of physiological and ecological effects to fauna has been reported for gaseous and particulate pollutants (Newman, 1981; Newman and Schreiber, 1988). The most severe of these effects have been observed at concentrations above the secondary NAAQS. Physiological and behavioral effects have been observed in experimental animals at or below these standards. For impacts on wildlife, the lowest threshold values of NO_x, and particulates that are reported to cause physiological changes are shown in Table 7-1.

7.2.4 Impact Analysis Methodology

A screening approach was used that compared the Project's maximum predicted ambient concentrations of air pollutants of concern in the vicinity of the site and the ENP PSD Class I Area with effect threshold limits for both vegetation and wildlife as reported in the scientific literature. A literature search was conducted to determine the effects of air contaminants on plant species as well as those species reported to occur in the vicinity of the site and in the PSD Class I area. It is recognized that effect threshold information is not available for all species found in these areas, although studies have been performed on a few of the common species and on other species known to be sensitive indicators of effects. Species of lichens, which are symbiotic organisms comprised of green or blue-green algae and fungi, have been used worldwide as air pollution monitors because relatively low levels of sulfur-, nitrogen-, and fluorine-containing pollutants adversely affect many species, altering lichen community composition, growth rates, reproduction, physiology, and morphological appearance (Blett et al., 2003).

7.3 Impacts on Soils, Vegetation, Wildlife, and Visibility in the Project's Vicinity

7.3.1 Impacts on Vegetation and Soils

Vegetative communities in the vicinity of the plant area are red mangrove (*Rhizophora mangle*), tidal dwarf red mangrove, buttonwood (*Conocarpus erectus*), white mangrove (*Laguncularia racemosa*), and black mangrove (*Avicennia germinans*). The red mangroves that are found in the tidal flats are characteristic of the dwarf mangrove community, reduced in size due to higher salinities and reduced tidal flushing. Additional vegetative species observed within the mangrove community include occasional Brazilian pepper (*Schinus terebinthfolius*), Australian pine (*Casuarina equisetifolia*), tree seaside oxeye (*Borrichia arborescens*), grey nicker (*Caesalpinia bonduc*), groundsel tree (*Baccharis halimifolia*), and cordgrass (*Spartina* sp.).

Soils in the area are primarily histosols, which are peat soils with high amounts of organic matter. The agricultural lands to the west of the site are part of the Everglades Agricultural Area, which is noted for its "muck" (i.e., rich, black soil that is very fertile).

According to the modeling results presented in Section 6.0, the maximum air quality impacts due to the proposed Project are predicted to be below the NAAQS and PSD increments. The NAAQS were established to protect both public health and welfare. Public welfare is protected by the secondary NAAQS, which Florida has adopted. Secondary standards set limits to protect public welfare, including protection against visibility impairment, damage to animals, crops, vegetation, and buildings (EPA, 2007).

Since the project's impacts on the local air quality are predicted to be less than the NAAQS and less than the effect levels on soils and vegetation, the project's impacts on soils, vegetation, and wildlife in the vicinity of the site are expected to be negligible. With regard to O_3 concentrations, the Project's VOC and NO_x emissions (precursors to O_3 formation) represent an insignificant increase in VOC and NO_x emissions for Lee County.

7.3.2 *Impacts on Wildlife*

The major air quality risk to wildlife in the United States is from continuous exposure to pollutants above the NAAQS. This occurs in non-attainment areas. Risks to wildlife also may occur for wildlife living in the vicinity of an emission source that experiences frequent upsets or episodic conditions resulting from malfunctioning equipment, unique meteorological conditions, or startup operations (Newman and Schreiber, 1988). Under these conditions, chronic effects (e.g., particulate contamination) and acute effects (e.g., injury to health) have been observed (Newman, 1981).

Although air pollution impacts to wildlife have been reported in the literature, many of the incidents involved acute exposures to pollutants, usually caused by unusual or highly concentrated releases or unique weather conditions. It is highly unlikely that emissions from the FPL Fort Myers Plant will cause adverse effects to wildlife due to the new CT Project's low impacts, which are predicted to be below the NAAQS based on worst-case operation. Coupled with the mobility of wildlife, the potential for exposure of wildlife to the project's impacts is extremely unlikely. In addition, the Project replaces 12 GTs located at the existing Fort Myers Plant which is expected to provide a huge improvement in the air quality of the area.

7.4 Impacts to the Everglades National Park PSD Class I Area

7.4.1 *Identification of AQRVs and Methodology*

An AQRV analysis was conducted to assess the potential risk to AQRVs at the ENP due to the emissions from the proposed Project. The ENP is located between 96.9 and 224.9 km and to the southeast of the Fort Myers Plant and is the only PSD Class I area located within 200 km.

The U.S. Department of the Interior in 1978 defined AQRVs to be:

- All those values possessed by an area except those that are not affected by changes in air quality and include all those assets of an area whose vitality, significance, or integrity is dependent in some way upon the air environment. These values include visibility and those scenic, cultural, biological, and recreational resources of an area that are affected by air quality.
- Important attributes of an area are those values or assets that make an area significant as a national monument, preserve, or primitive area. They are the assets that are to be preserved if the area is to achieve the purposes for which it was set aside (Federal Register, 1978).

The AQRVs include visibility, freshwater and coastal wetlands, dominant plant communities, unique and rare plant communities, soils and associated periphyton, and the wildlife dependent on these communities for habitat. Rare, endemic, threatened, and endangered species of the national park and bioindicators of air pollution (e.g., lichens) are also evaluated.

7.4.2 *Impacts to Soils*

The soils of the ENP are generally classified as histosols or entisols. Histosols (peat soils) are organic and have extremely high buffering capacities based on their CEC, base saturation, and bulk density. Therefore, they would be relatively insensitive to atmospheric inputs. The entisols are shallow sandy soils overlying limestone, such as the soils found in the pinelands. The direct connection of these soils with subsurface limestone tends to neutralize any acidic inputs. Moreover, the groundwater table is highly buffered due to the interaction with subsurface limestone formations, which results in high alkalinity (as $CaCO_3$).

The relatively low sensitivity of the soils to acid inputs, coupled with the low ground-level concentrations of air pollutants predicted from the proposed Project emissions, precludes any significant impact on soils at the ENP.

7.4.3 *Impacts to Vegetation*

Nitrogen Dioxide

The maximum 1-, 3-, and 8-hour average NO_2 concentrations due to the proposed Project are predicted to be 2.25, 1.42, and 0.67 µg/m^3, respectively, at the ENP. These concentrations are approximately 0.02 to 0.06 percent of the levels that could potentially injure 5 percent of vascular plant foliage (i.e., 3,800 to 15,000 µg/m^3; see previous subsections), and 0.1 to 0.4 percent of the concentration that caused adverse effects in lichen species in acute exposure scenarios (564 µg/m^3; see previous subsections). For a chronic exposure, the maximum annual NO_2 concentration due to the Project is predicted to be 0.009 µg/m^3 at the Class I area, which is less than 0.0005 percent of the levels that caused minimal yield loss and chlorosis in plant tissue (i.e., 2,000 µg/m^3; see previous subsections).

Although it has been shown that simultaneous exposure to SO_2 and NO_2 results in synergistic plant injury (Ashenden and Williams, 1980), the magnitude of this response is generally only 3 to 4 times greater than either gas alone, and usually occurs at unnaturally high levels of each gas. Therefore, the project's predicted concentrations at the ENP are still far below the levels that potentially cause plant injury for either acute or chronic exposure.

Particulate Matter

The maximum 8-hour PM_{10} concentration due to the Project is predicted to be 0.23 µg/m^3 at the ENP. This impact is 0.11 percent of the values that affected plant foliage (i.e., 210 µg/m^3, see previous subsections). As a result, no significant effects to vegetative AQRVs within the ENP are expected as a result of the Project's PM emissions.

Carbon Monoxide

The maximum 1-hour average concentration due to the project is 0.87 $\mu g/m^3$ in the Class I area, which is less than 0.00014 percent of the minimum value that caused inhibition in laboratory studies (i.e., 6.85×10^6 $\mu g/m^3$, see previous subsections). The amount of damage sustained at this level, if any, for 1 hour would have negligible effects over an entire growing season. The maximum predicted annual concentration of 0.008 $\mu g/m^3$ reflects a more realistic, yet conservative, CO impact level for the Class I area. This maximum concentration is 0.000001 percent of the value that caused cytochrome *c* oxidase inhibition (6.85×10^5 $\mu g/m^3$).

VOC and NO_X Emissions and Impacts to Ozone

VOC and NO_x emissions are precursors to O_3 formation. Since the proposed Project includes retirement of 12 GTs at the Fort Myers plant, the VOC and NO_x emissions will actually decrease in Lee County.

Summary

In summary, the phytotoxic effects of the new CT project's emissions within the ENP are expected to be minimal. It is important to note that emissions were evaluated with the assumption that 100 percent was available for plant uptake. This is rarely the case in a natural ecosystem.

7.4.4 Impacts to Wildlife

The Project's low emissions are well below the NAAQS, which are protective of soils, vegetation, and wildlife resources. The maximum predicted impacts of the project in the Class I area are up to six orders of magnitude lower than values of potential impacts to wildlife shown in Table 7-1. No significant effects on wildlife AQRVs from NO_x, CO, PM, or VOCs are expected.

7.4.5 Impacts Upon Visibility

Introduction

The CAA Amendments of 1977 provide for implementation of guidelines to prevent visibility impairment in mandatory Class I areas. The guidelines are intended to protect the aesthetic quality of these pristine areas from reduction in visual range and atmospheric discoloration due to various pollutants. Sources of air pollution can cause visible plumes if emissions of PM_{10} and NO_x are sufficiently large. A plume will be visible if its constituents scatter or absorb sufficient light so that the plume is brighter or darker than its viewing background (e.g., the sky or a terrain feature, such as a mountain). PSD Class I areas, such as national parks and wilderness areas, are afforded special visibility protection designed to prevent plume visual impacts to observers within a Class I area.

Visibility is an AQRV for the ENP. 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 closest approach of the ENP from the Fort Myers Plant is 96.9 km the change in visibility was analyzed as regional haze and the following methodology was used to address AQRVs.

Methodology

Based on the FLAG document, current regional haze guidelines characterize a change in visibility by the change in the light-extinction coefficient (b_{ext}). The b_{ext} is the attenuation of light per unit distance due to the scattering and absorption by gases and particles in the atmosphere. A change in the extinction coefficient produces a perceived visual change. An index that simply quantifies the percent change in visibility due to the operation of a source is calculated as:

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

where: b_{exts} = the extinction coefficient calculated for the source
b_{extb} = the background extinction coefficient

The analysis was conducted in accordance with the most recent guidance from the FLM's AQRV Workgroup (FLAG) Phase I Report (June 27, 2008) (FLAG) document. The purpose of the visibility analysis is to calculate the extinction at each receptor for each day (24-hour period) of the year due to the proposed project. The visibility threshold is a change in extinction of 5 percent (or 0.5 deciviews) and the threshold is not exceeded if the 98^{th}-percentile change in light extinction is less than 5 percent or 0.5 deciview for each modeled year.

Processing of visibility impairment for this study was performed with the California Puff (CALPUFF, Version 5.8) model and the CALPUFF post-processing program CALPOST Version 6.221. The CALPUFF postprocessor model CALPOST is used to calculate the combined visibility effects from the different pollutants that are emitted from the Project. For predicting visibility impairment, the FLAG guidance recommends using Method 8 (MVISBK = 8) and submode 5 (M8_MODE = 5). For this analysis, the background hygroscopic and non-hygroscopic aerosol levels were derived from the 20 percent best natural background days.

Emissions input to CALPUFF include the maximum rates for SO_2, NO_2, PM, and sulfuric acid mist.

The effect that each species has on visibility impairment is related to a parameter called the extinction coefficient. The higher the extinction coefficient, the greater is that species' effect on visibility.

Filterable PM was speciated into coarse (PMC), fine (PMF), and elemental carbon (EC). The default extinction efficiencies for these species are 0.6, 1.0, and 10.0, respectively. PMC is PM with aerodynamic diameters greater than 2.5 microns. Both EC and PMF have aerodynamic diameters equal to or less than 2.5 microns. Condensable PM was speciated into sulfate (SO_4) and secondary organic aerosols (SOA). The extinction efficiencies for these species are 3 x f(RH) and 4, respectively, where f(RH) is the relative humidity adjustment factor. These speciations were conducted in POSTUTIL.

Results are provided for both natural gas and ULSD oil firing.

Results

The results of the visibility analysis at the ENP are presented in Table 7-2. When firing natural gas, the maximum predicted visibility impairment is 0.05 dv which is well below the FLM's criteria of a 0.5 change in dv. For ULSD oil, the predicted impact is 0.21 dv (for Siemens CTs), based on a conservative 10 hours per day for 365 days per year. As a result, the Project is not expected to have an adverse impact on the existing regional haze at the PSD Class I area of the ENP.

7.4.6 Nitrogen Deposition

General Methods

As part of the AQRV analyses, total nitrogen (N) deposition rate was predicted for the project at the ENP. The deposition analysis criterion is based on the annual averaging period. The total deposition is estimated in units of kilograms per hectare per year (kg/ha/yr) of N. The CALPUFF model is used to predict wet and dry deposition fluxes of various oxides of these elements.

For N deposition, the species include:

- Particulate ammonium nitrate (from species NO_3), wet and dry deposition;
- Nitric acid (species HNO_3), wet and dry deposition;
- Nitrogen oxides (NO_x), dry deposition; and
- Ammonium sulfate (species SO_4), wet and dry deposition.

The CALPUFF model produces results in units of micrograms per square meter per second ($\mu g/m^2/s$), which are then converted to units of kg/ha/yr.

Deposition analysis threshold (DATs) for total nitrogen deposition of 0.01 kg/ha/yr was provided by the FLM (January 2002). A DAT is the additional amount of nitrogen deposition within a Class I area below which estimated impacts from a new or modified source are considered insignificant. The maximum deposition predicted for the project is, therefore, compared to this DATs or significant impact levels.

Results

The maximum predicted total annual nitrogen deposition due to the proposed project at the ENP is summarized in Table 7-3. The maximum annual deposition rate predicted for the project is 0.0010 kg/ha/yr which is well below the FLM's criteria of 0.01 kg/ha/yr.

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TABLES

Table 2-1a: Stack, Operating, and Emission Data for Combustion Turbines (CT)—Natural Gas Combustion GE 7FA.05

		Simple Cycle Operation								
		Base Load Turbine Inlet Temperature			75% Load Turbine Inlet Temperature			50% Load Turbine Inlet Temperature		
Parameter	Units	35° F	75° F	95° F	35° F	75° F	95° F	35° F	75° F	95° F
CT Stack Data										
Height	ft	100.5	100.5	100.5	100.5	100.5	100.5	100.5	100.5	100.5
Diameter	ft	23	23	23	23	23	23	23	23	23
Temperature	°F	1,098	1,117	1,132	1,109	1,174	1,209	1,202	1,215	1,215
Velocity	ft/sec	114.69	112.57	108.30	93.10	90.63	88.06	78.83	78.24	78.89
Maximum Hourly Emissions per Unit										
SO_2	gr/100 cf	2	2	2	2	2	2	2	2	2
	lb/hr	13.2	12.5	11.8	10.5	10.0	9.5	8.3	8.0	7.8
$PM_{10}/PM_{2.5}$	lb/hr	10.6	10.6	10.6	10.6	10.6	10.6	10.6	10.6	10.6
NO_x	ppmvd@15%O2	9	9	9	9	9	9	9	9	9
	lb/hr	72.0	68.1	64.3	57.0	54.1	52.0	45.2	43.2	42.1
CO	ppmvd@15%O2	7.16	7.26	7.20	7.33	7.08	6.92	7.36	7.50	7.65
	lb/hr	35.0	33.4	31.3	28.2	26.0	24.2	23.0	22.0	22.0
VOC (as methane)	ppmvd@15%O2	1.02	1.03	1.00	1.05	1.00	0.96	1.06	1.06	1.07
	lb/hr	3.4	3.3	3.1	2.7	2.5	2.4	2.2	2.1	2.2
Sulfuric Acid Mist	lb/hr	1.2	1.2	1.1	1.0	0.9	0.9	0.8	0.7	0.7

Source: General Electric Company, 2013 (CT Performance Data); Golder, 2013.

Table 2-1b: Stack, Operating, and Emission Data for Combustion Turbines (CT)—Natural Gas Combustion Siemens F5

		Simple Cycle Operation					
		Base Load Turbine Inlet Temperature			40% Load Turbine Inlet Temperature		44% Load Turbine Inlet Temperature
Parameter	**Units**	**35°F**	**75°F**	**95°F**	**35°F**	**75°F**	**95°F**
CT Stack Data							
Height	ft	100.5	100.5	100.5	100.5	100.5	100.5
Diameter	ft	23	23	23	23	23	23
Temperature	°F	1,107	1,108	1,127	1,118	1,154	1,176
Velocity	ft/sec	115.6	124.0	118.0	75.5	76.1	76.5
Maximum Hourly Emissions per Unit							
SO_2	gr/100 cf	2	2	2	2	2	2
	lb/hr	12.6	12.9	12.0	6.9	6.9	6.9
$PM_{10}/PM_{2.5}$	lb/hr	9	10	9	8	8	8
NO_x	ppmvd@15%O2	9	9	9	9	9	9
	lb/hr	77	79	74	42	42	42
CO	ppmvd@15%O2	4	4	4	9	9	9
	lb/hr	21	21	20	26	26	26
VOC (as methane)	ppmvd@15%O2	1	1	1	1	1	1
	lb/hr	3.0	3.1	2.9	1.6	1.6	1.6
Sulfuric Acid Mist	lb/hr	1.3	1.3	1.2	0.7	0.7	0.7

Source: Siemens, 2013 (CT Performance Data); Golder, 2013.

Table 2-2a: Stack, Operating, and Emission Data for Combustion Turbines (CT)-ULSD Oil Combustion GE 7FA.05

Parameter	Units	Simple Cycle Operation: Base Load Turbine Inlet Temperature 35° F	75° F	95° F	75% Load Turbine Inlet Temperature 35° F	75° F	95° F	50% Load Turbine Inlet Temperature 35° F	75° F	95° F
CT Stack Data										
Height	ft	100.5	100.5	100.5	100.5	100.5	100.5	100.5	100.5	100.5
Diameter	ft	23	23	23	23	23	23	23	23	23
Temperature	°F	1,107	1,106	1,118	1,143	1,177	1,190	1,215	1,215	1,215
Velocity	ft/sec	109.38	114.03	110.64	90.78	91.65	89.67	75.67	76.14	75.00
Maximum Hourly Emissions per Unit										
SO_2	%S	0.0015%	0.0015%	0.0015%	0.0015%	0.0015%	0.0015%	0.0015%	0.0015%	0.0015%
	lb/hr	3.62	3.62	3.42	2.89	2.86	2.72	2.25	2.20	2.09
$PM/PM_{10}/PM_{2.5}$	lb/hr	37.1	37.1	37.1	37.1	37.1	37.1	37.1	37.1	37.1
NO_x	ppmvd@15%O2	42	42	42	42	42	42	42	42	42
	lb/hr	370.3	369.9	349.4	295.1	291.9	277.2	229.5	224.1	213.6
CO	ppmvd@15%O2	13.15	13.61	13.75	13.49	13.31	13.49	13.96	14.26	14.63
	lb/hr	71.0	73.0	70.0	58.0	56.3	54.2	46.4	46.3	45.3
VOC (as methane)	ppmvd@15%O2	2.03	2.08	2.09	3.93	3.98	4.02	3.90	3.93	3.96
	lb/hr	7.99	8.34	8.03	9.61	9.63	9.23	7.41	7.30	7.01
Sulfuric Acid Mist	lb/hr	0.36	0.36	0.34	0.29	0.29	0.27	0.22	0.22	0.21
Lead	lb/hr	0.032	0.032	0.030	0.025	0.025	0.024	0.020	0.019	0.018

Source: General Electric Company, 2013 (CT Performance Data); Golder, 2013.

Table 2-2b: Stack, Operating, and Emission Data for Combustion Turbines (CT)-ULSD Oil Combustion Siemens F5

		Simple Cycle Operation					
		Base Load Turbine Inlet Temperature			50% Load Turbine Inlet Temperature		
Parameter	Units	35°F	75°F	95°F	35°F	75°F	95°F
CT Stack Data							
Height	ft	100.5	100.5	100.5	100.5	100.5	100.5
Diameter	ft	23	23	23	23	23	23
Temperature	°F	1,040	1,067	1,086	1,066	1,112	1,134
Velocity	ft/sec	118.9	121.5	115.9	83.7	83.1	80.7
Maximum Hourly Emissions per Unit							
SO_2	%S	0.0015%	0.0015%	0.0015%	0.0015%	0.0015%	0.0015%
	lb/hr	3.38	3.34	3.14	2.09	2.03	1.93
$PM/PM_{10}/PM_{2.5}$	lb/hr	53	52	48	37	35	33
NO_x	ppmvd@15%O2	42	42	42	42	42	42
	lb/hr	378	376	353	235	228	217
CO	ppmvd@15%O2	9	9	9	100	100	100
	lb/hr	49.0	49.0	46.0	340.0	331.0	315.0
VOC (as methane)	ppmvd@15%O2	1	1	1	20	20	20
	lb/hr	3.1	3.1	2.9	39.0	37.9	36.1
Sulfuric Acid Mist	lb/hr	0.34	0.33	0.31	0.21	0.20	0.19
Lead	lb/hr	0.031	0.031	0.029	0.019	0.019	0.018

Source: Siemens, 2013 (CT Performance Data); Golder, 2013.

Table 2-3a: Summary of Maximum Potential Annual Emissions for the Combustion Turbines
GE 7FA.05

								Maximum Emissions (tons/year)					
							Operating Scenario	Operating Hours					
							SC-NG 100 % Load	3,390	2,890	2,890	2,890	3,390	3,390
							SC-ULSD 100 % Load	0	500	0	0	0	0
							SC-NG 75 % Load	0	0	0	0	0	0
							SC-ULSD 75 % Load	0	0	500	0	0	0
	Maximum Hourly Emissions (lb/hr)						SC-NG 50 % Load	0	0	0	0	0	0
	Fuel for Ambient Temperature and Load						SC-ULSD 50 % Load	0	0	0	500	0	0
Pollutant	**SC-NG 75 °F 100% Load**	**SC-ULSD 75 °F 100% Load**	**SC-NG 75 °F 75% Load**	**SC-ULSD 75 °F 75% Load**	**SC-NG 75 °F 50% Load**	**SC-ULSD 75 °F 50% Load**	**TOTAL**	**3,390**	**3,390**	**3,390**	**3,390**	**3,390**	**3,390**
One Combustion Turbine													
SO_2	12.5	3.6	10.0	2.9	8.0	2.2		21.2	19.0	18.8	18.7	21.2	21.2
$PM/PM_{10}/PM_{2.5}$	10.6	37.1	10.6	37.1	10.6	37.1		18.0	24.6	24.6	24.6	18.0	18.0
NO_x	68.1	369.9	54.1	291.9	43.2	224.1		115.4	190.8	171.3	154.4	115.4	115.4
CO	33.4	73.0	26.0	56.3	22.0	46.3		56.6	66.5	62.4	59.9	56.6	56.6
VOC (as methane)	3.3	8.3	2.5	9.6	2.1	7.3		5.6	6.9	7.2	6.6	5.6	5.6
Sulfuric Acid Mist	1.2	0.4	0.9	0.3	0.7	0.2		2.0	1.8	1.8	1.7	2.0	2.0
Lead	0.0	0.032	0.0	0.025	0.0	0.019		0.00	0.01	0.01	0.00	0.00	0.00
Three Combustion Turbines													
SO_2	37.6	10.9	29.9	8.6	23.9	6.6		64	57	56	56	64	64
$PM/PM_{10}/PM_{2.5}$	31.8	111.3	31.8	111.3	31.8	111.3		54	74	74	74	54	54
NO_x	204.2	1109.7	162.3	875.6	129.7	672.2		346	572	514	463	346	346
CO	100.2	219.0	78.0	168.9	66.0	139.0		170	200	187	180	170	170
VOC (as methane)	9.9	25.0	7.6	28.9	6.4	21.9		16.8	20.6	21.5	19.8	16.8	16.8
Sulfuric Acid Mist	3.5	1.1	2.8	0.9	2.2	0.7		6.0	5.4	5.3	5.2	6.0	6.0
Lead	0.00	0.09	0.00	0.07	0.00	0.06		0.00	0.02	0.02	0.01	0.00	0.00

Source: General Electric Company, 2013

Table 2-3b: Summary of Maximum Potential Annual Emissions for the Combustion Turbines Siemens F5

	Maximum Hourly Emissions (lb/hr) Fuel for Ambient Temperature and Load					Maximum Emissions (tons/year)					
					Operating Scenario	Operating Hours					
					SC-NG 100 % Load	3,390	2,890	0	2,890	1,890	2,390
					SC-FO 100 % Load	0	500	0	0	250	0
					SC-NG 40 % Load	0	0	3390	0	1000	1000
					SC-FO 50 % Load	0	0	0	500	250	0
Pollutant	SC-NG 75 °F 100% Load	SC-FO 75 °F 100% Load	SC-NG 75 °F 40% Load	SC-FO 75 °F 50% Load	TOTAL	3,390	3,390	3,390	3,390	3,390	3,390
One Combustion Turbine											
SO_2	12.9	3.3	6.9	2.0		21.8	19.4	11.7	19.1	16.3	18.8
$PM/PM_{10}/PM_{2.5}$	10.0	52.0	8.0	35.0		17.0	27.5	13.6	23.2	24.3	16.0
NO_x	79.0	376.0	42.0	228.0		133.9	208.2	71.2	171.2	171.2	115.4
CO	21.0	49.0	26.0	331.0		35.6	42.6	44.1	113.1	80.3	38.1
VOC (as methane)	3.1	3.1	1.6	37.9		5.3	5.3	2.7	14.0	8.9	4.5
Sulfuric Acid Mist	1.29	0.33	0.69	0.20		2.18	1.94	1.17	1.91	1.63	1.88
Lead	0.0	0.031	0.0	0.019		0.000	0.008	0.000	0.005	0.006	0.000
Three Combustion Turbines											
SO_2	38.6	10.0	20.7	6.1		65	58	35	57	49	56
$PM/PM_{10}/PM_{2.5}$	30.0	156.0	24.0	105.0		50.9	82.4	40.7	70	73	48
NO_x	237.0	1128.0	126.0	684.0		402	624	214	513	513	346
CO	63.0	147.0	78.0	993.0		107	128	132	339	241	114
VOC (as methane)	9.30	9.30	4.80	113.70		15.76	15.76	8.14	41.86	26.56	13.51
Sulfuric Acid Mist	3.9	1.0	2.1	0.6		6.5	5.8	3.5	5.7	4.9	5.6
Lead	0.00	0.09	0.00	0.06		0.000	0.023	0.000	0.014	0.019	0.000

Source: General Electric Company, 2013

Table 2-4: Performance and Emission Data for the Black Start Diesel Engine

Parameter		Units	Values	
Performance				
Number of Units			1	4
Rating		kW	3,100	12,400
Rating		hp	4,157	16,629
Fuel			Diesel	Diesel
Fuel Heat content (HHV)		Btu/lb	19,500	19,500
Fuel density		lb/gal	7	7.06
Heat input (HHV)		MMBtu/hr	29	116
Fuel usage		gal/hr	211	843
Maximum operation/yr		hours	100	400
Maximum fuel usage		gal/yr	21,070	84,280
Stack Parameters				
Height		ft	30.0	30.0
Diameter		ft	2.0	2.0
Temperature		°F	893.0	893.0
Flow		acfm	24282.7	24,283
Emissions				
SO_2 -	Basis	%S	0.0015%	
	Conversion of S to SO_2	%	100	
	Molecular weight SO_2/ S (64/32)		2	
	Emission rate	lb/hr	0.045	0.179
		TPY	0.0022	0.0089
NO_x -	Basis	g/hp-hr	5.19	
	Emission rate	lb/hr	47.57	190.26
		TPY	2.38	9.51
CO -	Basis	g/hp-hr	0.65	
	Emission rate	lb/hr	5.96	23.83
		TPY	0.30	1.19
VOC -	Basis	g/hp-hr	0.10	
	Emission rate	lb/hr	0.92	3.67
		TPY	0.05	0.18
$PM/PM_{10}/PM_{2.5}$ -	Basis	g/hp-hr	0.03	
	Emission rate	lb/hr	0.27	1.10
		TPY	0.01	0.05

Source: FPL, Golder; 2011.

Based on Caterpillar Standby 3,100 kW 60 Hz 900 Diesel Generator (2013) meeting 40 CFR Part 60 Subpart IIII Requirements for Tier 2 engines.

Table 2-5a: Summary of Maximum Potential Annual Emissions
GE 7FA.05

Pollutant	Project Maximum Potential Annual Emissions (TPY)			Netting Calculations			
	3	4		Maximum 2-Year Average from Existing Units [b]	Change	PSD Significant Emission Rate	PSD Review Required?
	CT [a]	Black Start Diesel Engines	TOTAL	(TPY)	(TPY)	(TPY)	
SO_2	64	0.009	64	80	-16	40	NO
PM	74	0.05	74	3	71	25	YES
PM_{10}	74	0.05	74	3	71	15	YES
$PM_{2.5}$	74	0.05	74	3	71	10	YES
NO_x	572	9.51	582	148	434	40	YES
CO	200	1.19	201	11	190	100	YES
VOC (as methane)	21.5	0.18	21.7	0.3	21.4	40	NO
Sulfuric Acid Mist	6.0	Neg.	6	12.2	-6	7	NO
Lead	0.024	Neg.	0	NA	0.024	0.6	NO
Greenhouse Gases (CO_2e)	445,721	237	445,958	36,046	409,912	75,000	YES

[a] Based on SC operation for: 3,390 hours (maximum).
[b] Based on actual emissions from Annual Operating Reports from 2008-2012.

Note: Neg.= negligible; NA= not applicable

Source: Golder, 2013.

Table 2-5b: Summary of Maximum Potential Annual Emissions
Siemens F5

Pollutant	Project Maximum Potential Annual Emissions (TPY) 3 CT [a]	4 Black Start Diesel Engines	TOTAL	Netting Calculations: Maximum 2-Year Average from Existing Units [b] (TPY)	Change (TPY)	PSD Significant Emission Rate (TPY)	PSD Review Required?
SO_2	65	0.015	65	80	-14	40	NO
PM	82	0.09	82	3	80	25	YES
PM_{10}	82	0.09	82	3	80	15	YES
$PM_{2.5}$	82	0.09	82	3	80	10	YES
NO_x	624	16.33	641	148	493	40	YES
CO	339	2.04	341	11	331	100	YES
VOC (as methane)	41.9	0.31	42.2	0.3	41.9	40	YES
Sulfuric Acid Mist	6.5	Neg.	7	12.2	-6	7	NO
Lead	0.023	Neg.	0	--	0.023	0.6	NO
Greenhouse Gases (CO_2e)	477,915	1,548	479,463	36,046	443,417	75,000	YES

[a] Based on SC operation for: 3,390 hours (maximum).
[b] Based on actual emissions from Annual Operating Reports from 2008-2012.

Note: Neg.= negligible; NA= not applicable

Source: Golder, 2013.

Table 2-6a: Summary of Maximum Potential Annual HAP Emissions
GE 7FA.05

Pollutant	Maximum Potential Annual Emissions (TPY) 3 CT		4 Black Start Diesel Engines		TOTAL	HAP Major Source Threshold (TPY)
Total HAPs	4.8		0.009		4.8	25
Single HAP	2.2	a	0.005	b	2.2	10

Note: NA= not applicable.

[a] Based on formaldehyde emissions
[b] Based on benzene emissions

Source: Golder, 2013

Table 2-6b: Summary of Maximum Potential Annual HAP Emissions
Siemens F5

Pollutant	Maximum Potential Annual Emissions (TPY) 3 CT		4 Black Start Diesel Engines		Total	HAP Major Source Threshold (TPY)
Total HAPs	5.2		0.015		5.2	25
Single HAP	2.4	a	0.007	b	2.4	10

Note: NA= not applicable.

[a] Based on formaldehyde emissions
[b] Based on benzene emissions

Source: Golder, 2013

Table 3-1: National and State AAQS, Allowable PSD Increments and Significant Impact Levels

Pollutant	Averaging Time	National and Florida AAQS (µg/m³)		PSD Increments (µg/m³)		Significant Impact Levels (µg/m³)	
		Primary Standard	Secondary Standard	Class I	Class II	Class I	Class II
Particulate Matter (PM_{10}) [a]	Annual Arithmetic Mean	NA	NA	4	17	0.2	1
	24-Hour Maximum	150	150	4	30	0.3	5
Particulate Matter ($PM_{2.5}$) [a]	Annual Arithmetic Mean	12	15	1	4	0.06	0.3
	24-Hour Maximum	35	35	2	9	0.07	1.2
Sulfur Dioxide [b]	Annual Arithmetic Mean	80	NA	2	20	0.1	1
	24-Hour Maximum	365	NA	5	91	0.2	5
	3-Hour Maximum	NA	1,300	25	512	1	25
	1-Hour Maximum	197	NA	NA	NA	NA	7.9 [e]
Carbon Monoxide	8-Hour Maximum	10,000	10,000	NA	NA	NA	500
	1-Hour Maximum	40,000	40,000	NA	NA	NA	2,000
Nitrogen Dioxide [c]	Annual Arithmetic Mean	100	100	2.5	25	0.1	1
	1-Hour Maximum	188	NA	NA	NA	NA	7.6 [e]
Ozone [d]	1-Hour Maximum	NA	NA	NA	NA	NA	NA
	8-Hour Maximum	147	147	NA	NA	NA	NA
Lead	*Rolling* 3-Month Average	0.15	0.15	NA	NA	NA	NA

Note: NA = not applicable.
AAQS = ambient air quality standard.

[a] On October 17, 2006, EPA promulgated revised PM_{10} and $PM_{2.5}$ AAQS; the $PM_{2.5}$ AAQS had been promulgated on July 18, 1997. For PM_{10}, the annual standard was revoked and the 24-hour standard was retained. The 24-hour $PM_{2.5}$ standard was revised to 35 µg/m³ based on the 3-year averages of the 98th percentile values. The annual $PM_{2.5}$ standard of 15 µg/m³, 3-year averages at community monitors, was retained.

[b] On June 23, 2010, EPA promulgated the 1-hour SO_2 standard at a level of 75 parts per billion (ppb), based on the 3-year average of the annual 99th percentile of 1-hour daily maximum concentrations (effective August 23, 2010). EPA is also revoking both the existing 24-hour and annual primary SO_2 standards, effective one year after the designation of an area, pursuant to section 107 of the Clean Air Act.

[c] On February 9, 2010, EPA promulgated the 1-hour NO_2 standard at a level of 100 ppb, based on the 3-year average of the annual 99th percentile of 1-hour daily maximum concentrations (effective April 12, 2010).

[d] On March 27, 2008, EPA promulgated revised AAQS for ozone. The O_3 standard was modified to be 0.075 ppm (147 µg/m³) for the 8-hour average; achieved when the 3-year average of 99th percentile values is 0.075 ppm or less.

[e] For NO_2 and SO_2 1-hour averaging period, an interim Class II significant impact level is shown.

Sources: FR, Vol. 43, No. 118, June 19, 1978; 40 CFR 50; 40 CFR 52.21; Florida Chapter 62.204, F.A.C.
Golder, 2013.

Table 3-2: PSD Significant Emission Rates and De Minimis Monitoring Concentrations

Pollutant	Regulated Under	Significant Emission Rate (TPY)	De Minimis Monitoring Concentration (μg/m³) [a]
Sulfur Dioxide	NAAQS, NSPS	40	13, 24-hour
Particulate Matter [PM(TSP)]	NSPS	25	NA
Particulate Matter (PM_{10})	NAAQS	15	10, 24-hour
Particulate Matter ($PM_{2.5}$) [c]	NAAQS	10, or	4, 24-Hour
	NAAQS	40 of SO_2, or	NA
	NAAQS	40 of NO_X	NA
Nitrogen Dioxide	NAAQS, NSPS	40	14, annual
Carbon Monoxide	NAAQS, NSPS	100	575, 8-hour
Volatile Organic Compounds (Ozone)	NAAQS, NSPS	40 or NO_X	100 TPY[b]
Lead	NAAQS	0.6	0.1, 3-month
Sulfuric Acid Mist	NSPS	7	NM
Total Fluorides	NSPS	3	0.25, 24-hour
Total Reduced Sulfur	NSPS	10	10, 1-hour
Reduced Sulfur Compounds	NSPS	10	10, 1-hour
Hydrogen Sulfide	NSPS	10	0.2, 1-hour
Mercury	NESHAP	0.1	0.25, 24-hour
MWC Organics (dioxin/furans)	NSPS	$3.5x10^{-6}$	NM
MWC Metals (as PM)	NSPS	15	NM
MWC Acid Gases (SO_2 + HCl)	NSPS	40	NM
MSW Landfill Gases (as NMOC)	NSPS	50	NM
Greenhouse Gases [d]	--	0 (mass basis), and	NM
	--	75,000 (CO_2e basis)	NM

Note: Ambient monitoring requirements for any pollutants may be exempted if the impact of the increase is less than de minimis monitoring concentrations.

NA = not applicable

NM = no ambient measurement method established; therefore, no *de minimis* concentration has been established

mg/m³ = micrograms per cubic meter

MWC = municipal waste combustor

MSW = municipal solid waste

NMOC = non-methane organic compounds

[a] Short-term concentrations are not to be exceeded

[b] No *de minimis* concentration; an increase in VOC OR NO_x emissions of 100 TPY or more will require a monitoring analysis for ozone

[c] Any emission rate of these pollutants.

[d] On July 20, 2011, biogenic CO_2 emissions were deferred from consideration in the significant emission rates for 3 years. This deferral was vacated by the US Court of Appeals on July 12, 2013.

Source: 40 CFR 52.21.
Rule 62-212.400, F.A.C.

Table 3-3: Maximum Emission Changes Due to the Project Including Emission Reductions Due to the Existing GT Units 1 Through 12 Compared to the PSD Significant Emission Rates

	Pollutant Emissions		
Pollutant	**Net Emission Changes* (TPY)**	**Significant Emission Rate (TPY)**	**PSD Review**
Sulfur Dioxide	-14	40	No
Particulate Matter [PM (TSP)]	80	25	Yes
Particulate Matter (PM_{10})	80	15	Yes
Particulate Matter ($PM_{2.5}$)	80	15	Yes
Nitrogen Dioxide	493	40	Yes
Carbon Monoxide	331	100	Yes
Volatile Organic Compounds	41.9	40	Yes
Lead	0.023	0.6	No
Sulfuric Acid Mist	−6	7	No
Total Fluorides	NEG	3	No
Total Reduced Sulfur	NEG	10	No
Reduced Sulfur Compounds	NEG	10	No
Hydrogen Sulfide	NEG	10	No
Mercury	NEG	0.1	No
Greenhouse Gases	443,417	75,000	Yes

Note: NEG = Negligible.

* See Table 2-5B.

Table 4-1: Proposed BACT Emission Limits for CTs

Pollutant	CT(s)	Fuel	Operating Mode	Proposed BACT Emission Limits	Compliance Methods
NO_x	GE and S[a]	Natural Gas	Normal Operation[b]	9 ppmvd at 15% O_2	Initial: EPA Methods- 7E or 20, Continuous Monitoring (Subpart KKKK)
	GE and S[a]	ULSD Oil	Normal Operation[b]	42 ppmvd at 15% O_2	Initial: EPA Methods- 7E or 20, Continuous Monitoring (Subpart KKKK)
CO	GE and S[a]	Natural Gas	Baseload[b]	9 ppmvd at 15% O_2	Initial: EPA Method 10
	GE and S[a]	ULSD Oil	Baseload[b]	20 ppmvd	Initial: EPA Method 10
PM/PM_{10}	GE and S[a]	Natural Gas	Normal Operation[b]	10% Opacity	Initial/Annual: EPA Method 9
	GE and S[a]	ULSD Oil	Normal Operation[b]	10% Opacity	Initial/Annual: EPA Method 9
SO_2 and SAM[c]	GE and S[a]	Natural Gas	Normal Operation[b]	2 grains S/100 scf	Initial/Annual: 40 CFR Part 75 Fuel Sampling
	GE and S[a]	ULSD Oil	Normal Operation[b]	0.0015% S	Initial/Annual: 40 CFR Part 75 Fuel Sampling

Notes: CT = combustion turbine; ULSD = ultra low sulfur distillate; G = GE 7FA.05 or 7FA.04 CT; S = Siemens F5 CT
[a] or equivalent CT.
[b] excluding startup, shutdown and fuel switching.
[c] SO_2 and SAM fuel sulfur are proposed to demonstrate non-applicability of PSD and for PM/PM_{10} $PM_{2.5}$.

Table 4-2a: Capital Cost for Hot Selective Catalytic Reduction for Siemens Simple Cycle Combustion Turbine Based on 2,890 hr/yr Gas Firing and 500 hr/yr Oil Firing

Cost Component	Costs	Basis of Cost Component
Direct Capital Costs		
Hot SCR Associated Equipment	10,232,248	Cost of new Entry Estimates for Combustion-Turbine and Combined-Cycle Plants in PJM, 2011
Ammonia Storage Tank	included	
Flue Gas Ductwork	included	
Instrumentation	included	
Emission Monitoring	$511,612	5% of SCR Associated Equipment
Freight	$511,612	5% of SCR Associated Equipment
Total Direct Capital Costs (TDCC)	11,255,473	
Direct Installation Costs		
Foundation and supports	$900,438	8% of TDCC and RCC;OAQPS Cost Control Manual
Handling & Erection	$1,575,766	14% of TDCC and RCC;OAQPS Cost Control Manual
Electrical	$450,219	4% of TDCC and RCC;OAQPS Cost Control Manual
Piping (Ammonia Injection Grid)	included	Vendor Estimate
Insulation for ductwork	$112,555	1% of TDCC and RCC;OAQPS Cost Control Manual
Painting	$112,555	1% of TDCC and RCC;OAQPS Cost Control Manual
Site Preparation (General Facilities)	$562,774	5% of TDCC and RCC;OAQPS Cost Control Manual
Project Contingencies	$1,125,547	10% of TDCC and RCC;OAQPS Cost Control Manual
Total Direct Installation Costs (TDIC)	$4,839,853	
Total Capital Costs (TCC)	$16,095,326	Sum of TDCC and TDIC
Indirect Costs		
Engineering	included	
PSM/RMP Plan	$50,000	Engineering Estimate
Construction and Field Expense	$804,766	5% of Total Capital Costs; OAQPS Cost Control Manual
Contractor Fees	$1,609,533	10% of Total Capital Costs; OAQPS Cost Control Manual
Start-up	$321,907	2% of Total Capital Costs; OAQPS Cost Control Manual
Performance Tests	$160,953	1% of Total Capital Costs; OAQPS Cost Control Manual
Total Indirect Capital Cost (TInCC)	$2,947,159	
Total Direct, Indirect and Capital Costs (TDICC)	$19,042,485	Sum of TCC and TInCC

Table 4-2b: Capital Cost for Hot Selective Catalytic Reduction for General Electric Simple Cycle Combustion Turbine
Based on 2,890 hr/yr Gas Firing and 500 hr/yr Oil Firing.

Cost Component	Costs	Basis of Cost Component
Direct Capital Costs		
Hot SCR Associated Equipment	10,232,248	Cost of new Entry Estimates for Combustion-Turbine and Combined-Cycle Plants in PJM, 2011
Ammonia Storage Tank	included	
Flue Gas Ductwork	included	
Instrumentation	included	
Emission Monitoring	$511,612	5% of SCR Associated Equipment
Freight	$511,612	5% of SCR Associated Equipment
Total Direct Capital Costs (TDCC)	11,255,473	
Direct Installation Costs		
Foundation and supports	$900,438	8% of TDCC and RCC;OAQPS Cost Control Manual
Handling & Erection	$1,575,766	14% of TDCC and RCC;OAQPS Cost Control Manual
Electrical	$450,219	4% of TDCC and RCC;OAQPS Cost Control Manual
Piping (Ammonia Injection Grid)	included	Vendor Estimate
Insulation for ductwork	$112,555	1% of TDCC and RCC;OAQPS Cost Control Manual
Painting	$112,555	1% of TDCC and RCC;OAQPS Cost Control Manual
Site Preparation (General Facilities)	$562,774	5% of TDCC and RCC;OAQPS Cost Control Manual
Project Contingencies	$1,125,547	10% of TDCC and RCC;OAQPS Cost Control Manual
Total Direct Installation Costs (TDIC)	$4,839,853	
Total Capital Costs (TCC)	$16,095,326	Sum of TDCC and TDIC
Indirect Costs		
Engineering	included	
PSM/RMP Plan	$50,000	Engineering Estimate
Construction and Field Expense	$804,766	5% of Total Capital Costs; OAQPS Cost Control Manual
Contractor Fees	$1,609,533	10% of Total Capital Costs; OAQPS Cost Control Manual
Start-up	$321,907	2% of Total Capital Costs; OAQPS Cost Control Manual
Performance Tests	$160,953	1% of Total Capital Costs; OAQPS Cost Control Manual
Total Indirect Capital Cost (TInCC)	$2,947,159	
Total Direct, Indirect and Capital Costs (TDICC)	$19,042,485	Sum of TCC and TInCC

**Table 4-3a: Annualized Cost for Selective Catalytic Reduction for Siemens Simple Cycle Operatior
Based on 2,890 hr/yr Gas Firing and 500 hr/yr Oil Firing**

Cost Component	Costs	Basis of Cost Component
Direct Annual Costs		
Operating Personnel	$21,840	28 hours/week at $15/hr
Supervision	$3,276	15% of Operating Personnel;OAQPS Cost Control Manual
Ammonia	$33,979	$556 per ton for anhydrous NH_3, 3,390 hr/year
PSM/RMP Update	$25,000	Engineering Estimate
Inventory Cost	$12,316	Capital Recovery (9.44%) for 1/3 catalyst for SCR
Catalyst Replacement	$84,125	4 years catalyst life; Based on Vendor Budget Estimate
Contingency	$5,416	3% of Direct Annual Costs
Total Direct Annual Costs (TDAC)	$185,952	
Energy Costs		
Electrical (SCR and Cooling)	$246,928	330kWh for SCR system and 1,491kWh fan @ $0.04/kWh, 3,390 hr/yr
MW Loss and Heat Rate Penalty	$108,963	0.2% of MW output; EPA, 1993 (Page 6-20)[a] and $3/mmBtu addl fuel costs
Total Energy Costs (TEC)	$355,891	
Indirect Annual Costs		
Overhead	$35,457	60% of Operating/Supervision Labor and Ammonia
Property Taxes (exempt)	$0	0% of Total Capital Costs
Insurance	$190,425	1% of Total Capital Costs
Administration	$380,850	2% of Total Capital Costs
Annualized Total Direct Capital	$2,132,682	10.98% Capital Recovery Factor of 7% over 15 years times sum of TDICC
Total Indirect Annual Costs (TIAC)	$2,739,414	
Total Annualized Costs	$3,281,257	Sum of TDAC, TEC and TIAC
Incremental Cost Effectiveness(9 to 3 ppmvd gas and 42 to 14 oil)	$21,826	NO_x Reduction Only
	$35,686	Net Emission Reduction

[a] Alternative Control Techniques Document--NOx Emissions from Stationary Gas Turbines, Page 6-20.

Table 4-3b: Annualized Cost for Selective Catalytic Reduction for General Electric Simple Cycle Operation Based on 2,890 hr/yr Gas Firing and 500 hr/yr Oil Firing.

Cost Component	Costs	Basis of Cost Component
Direct Annual Costs		
Operating Personnel	$21,840	28 hours/week at $15/hr
Supervision	$3,276	15% of Operating Personnel;OAQPS Cost Control Manual
Ammonia	$31,099	$556 per ton for anhydrous NH_3, 3,390 hr/year
PSM/RMP Update	$25,000	Engineering Estimate
Inventory Cost	$12,316	Capital Recovery (9.44%) for 1/3 catalyst for SCR
Catalyst Replacement	$84,125	4 years catalyst life; Based on Vendor Budget Estimate
Contingency	$5,330	3% of Direct Annual Costs
Total Direct Annual Costs (TDAC)	$182,986	
Energy Costs		
Electrical (SCR and Cooling)	$246,928	330kWh for SCR system and 1,491kWh fan @ $0.04/kWh, 3,390 hr/yr
MW Loss and Heat Rate Penalty	$100,717	0.2% of MW output; EPA, 1993 (Page 6-20)[a] and $3/mmBtu addl fuel costs
Total Energy Costs (TEC)	$347,645	
Indirect Annual Costs		
Overhead	$33,729	60% of Operating/Supervision Labor and Ammonia
Property Taxes (exempt)	$0	0% of Total Capital Costs
Insurance	$190,425	1% of Total Capital Costs
Administration	$380,850	2% of Total Capital Costs
Annualized Total Direct Capital	$2,132,682	10.98% Capital Recovery Factor of 7% over 15 years times sum of TDICC
Total Indirect Annual Costs (TIAC)	$2,737,686	
Total Annualized Costs	$3,268,316	Sum of TDAC, TEC and TIAC
Incremental Cost Effectiveness(9 to 3 ppmvd gas and 42 to 14 oil)	$23,754	NO_x Reduction Only
	$39,616	Net Emission Reduction

[a] Alternative Control Techniques Document--NOx Emissions from Stationary Gas Turbines, Page 6-20.

Table 4-4. Maximum Potential Incremental Emissions (TPY) with Selective Catalytic Reduction Based on 2,890 hr/yr Gas Firing and 500 hr/yr Oil Firing

Pollutants		Incremental Emissions (tons/year) of SCR Primary	Secondary	Total
Particulate		6.12	0.18	6.29
Sulfur Dioxide			0.07	0.07
Nitrogen Oxides		-150.33	3.25	-147.09
Carbon Monoxide			1.95	1.95
Volatile Organic Compounds			0.13	0.13
Ammonia		46.71		46.71
	Total:	-97.51	5.56	-91.95
Carbon Dioxide (additonal from gas firing)			3,084.30	3,084.30

Table 4-5a: Direct and Indirect Capital Costs Oxidation Catalyst for Siemens Simple Cycle 2,890 hr/yr Natural Gas, 500 hr/yr Oil Fired

Cost Component	Costs	Basis of Cost Component
Direct Capital Costs		
CO Associated Equipment	$950,051	Based on Vendor Quote and Construction Cost Index
Auxiliary Equipment (ducts, catalyst housing)		Assumed included
Instrumentation	$95,005	10% of Oxidation Catalyst Associated Equipment
Freight	$47,503	5% of Oxidation Catalyst Associated Equipment
Total Direct Capital Costs (TDCC)	$1,092,558	
Direct Installation Costs		
Foundation and supports	$87,405	8% of TDCC and RCC;OAQPS Cost Control Manual
Handling & Erection	$152,958	14% of TDCC and RCC;OAQPS Cost Control Manual
Electrical	$43,702	4% of TDCC and RCC;OAQPS Cost Control Manual
Piping	$21,851	2% of TDCC and RCC;OAQPS Cost Control Manual
Insulation for ductwork	$10,926	1% of TDCC and RCC;OAQPS Cost Control Manual
Painting	$10,926	1% of TDCC and RCC;OAQPS Cost Control Manual
Site Preparation	$54,628	5% Engineering Estimate
Total Direct Installation Costs (TDIC)	$382,395	
Total Capital Costs	$1,474,954	Sum of TDCC, TDIC and RCC
Indirect Costs		
Engineering	$147,495	10% of Total Capital Costs; OAQPS Cost Control Manual
Construction and Field Expense	$73,748	5% of Total Capital Costs; OAQPS Cost Control Manual
Contractor Fees	$147,495	10% of Total Capital Costs; OAQPS Cost Control Manual
Start-up	$29,499	2% of Total Capital Costs; OAQPS Cost Control Manual
Performance Tests	$14,750	1% of Total Capital Costs; OAQPS Cost Control Manual
Total Indirect Capital Cost (TInDC)	$412,987	
Contingencies	$221,243	15% of Total Capital Costs
Total Direct, Indirect and Capital Costs (TDICC)	$2,109,184	Sum of TCC and TInCC

Table 4-5b: Direct and Indirect Capital Costs Oxidation Catalyst for GE Simple Cycle 2,890 hr/yr Natural Gas, 500 hr/yr Oil Fired

Cost Component	Costs	Basis of Cost Component
Direct Capital Costs		
CO Associated Equipment	$950,051	Based on Vendor Quote and Construction Cost Index
Auxiliary Equipment (ducts, catalyst housing)		Assumed included
Instrumentation	$95,005	10% of Oxidation Catalyst Associated Equipment
Freight	$47,503	5% of Oxidation Catalyst Associated Equipment
Total Direct Capital Costs (TDCC)	$1,092,558	
Direct Installation Costs		
Foundation and supports	$87,405	8% of TDCC and RCC;OAQPS Cost Control Manual
Handling & Erection	$152,958	14% of TDCC and RCC;OAQPS Cost Control Manual
Electrical	$43,702	4% of TDCC and RCC;OAQPS Cost Control Manual
Piping	$21,851	2% of TDCC and RCC;OAQPS Cost Control Manual
Insulation for ductwork	$10,926	1% of TDCC and RCC;OAQPS Cost Control Manual
Painting	$10,926	1% of TDCC and RCC;OAQPS Cost Control Manual
Site Preparation	$54,628	5% Engineering Estimate
Total Direct Installation Costs (TDIC)	$382,395	
Total Capital Costs	$1,474,954	Sum of TDCC, TDIC and RCC
Indirect Costs		
Engineering	$147,495	10% of Total Capital Costs; OAQPS Cost Control Manual
Construction and Field Expense	$73,748	5% of Total Capital Costs; OAQPS Cost Control Manual
Contractor Fees	$147,495	10% of Total Capital Costs; OAQPS Cost Control Manual
Start-up	$29,499	2% of Total Capital Costs; OAQPS Cost Control Manual
Performance Tests	$14,750	1% of Total Capital Costs; OAQPS Cost Control Manual
Total Indirect Capital Cost (TInDC)	$412,987	
Contingencies	$221,243	15% of Total Capital Costs
Total Direct, Indirect and Capital Costs (TDICC)	$2,109,184	Sum of TCC and TInCC

Table 4-6a: Annualized Cost for CO Catalyst for Siemens Simple Cycle Combustion Turbine

Cost Component	Cost	Basis of Cost Estimate
Direct Annual Costs		
Operating Personnel	$16,425	1/2 hr/shift, $30/hr, 8760 yr
Supervision	$2,464	15% of Operating Personnel;OAQPS Cost Control Manual
Maintenance (labor and materials)	$31,638	1.50% of TDICC, OAQPS Seciton 4
Inventory Cost	$37,200	7 year catalyst life, 50% catalyst replaced
Catalyst Replacement	$60,321	Capital Recovery (10.98%) for 1/3 catalyst
Contingency	$7,402	5% of Direct Annual Costs
Total Direct Annual Costs (TDAC)	$155,450	
Energy Costs		
Heat Rate Penalty	$108,963	0.2% of MW output; EPA, 1993 (Page 6-20) and $3/mmBtu addl fuel costs
Total Energy Costs (TDEC)	$108,963	
Indirect Annual Costs		
Overhead	$30,316	60% of Operating/Supervision Labor
Property Taxes (exempt)	$0	0% of Total Capital Costs
Insurance	$21,092	1% of Total Capital Costs
Administration	$42,184	2% of Total Capital Costs
Annualized Total Direct Capital	$231,588	10.98% Capital Recovery Factor of 7% over 15 yrs times sum of TDICC
Total Indirect Annual Costs	$325,180	
Total Annualized Costs	$589,593	Sum of TDAC, TEC and TIAC
	24.61	Net CO Emission Reduciton
Cost Effectiveness	$23,955	per ton of CO Removed
	$28,297	Net Emission Reduction

Table 4-6b: Annualized Cost for CO Catalyst for GE Simple Cycle Combustion Turbine

Cost Component	Cost	Basis of Cost Estimate
Direct Annual Costs		
Operating Personnel	$16,425	1/2 hr/shift, $30/hr, 8760 yr
Supervision	$2,464	15% of Operating Personnel;OAQPS Cost Control Manual
Maintenance (labor and materials)	$31,638	1.5% of TDICC, OAQPS Seciton 4
Catalyst Replacement	$60,321	7 year catalyst life, 50% catalyst replaced
Inventory Cost	$37,200	Capital Recovery (10.98%) for 1/3 catalyst
Contingency	$7,402	5% of Direct Annual Costs
Total Direct Annual Costs (TDAC)	$155,450	
Energy Costs		
Heat Rate Penalty	$100,717	0.2% of MW output; EPA, 1993 (Page 6-20) and $3/mmBtu addl fuel costs
Total Energy Costs (TDEC)	$100,717	
Indirect Annual Costs		
Overhead	$30,316	60% of Operating/Supervision Labor
Property Taxes (exempt)	$0	0% of Total Capital Costs
Insurance	$21,092	1% of Total Capital Costs
Administration	$42,184	2% of Total Capital Costs
Annualized Total Direct Capital	$231,588	10.98% Capital Recovery Factor of 7% over 15 yrs times sum of TDICC
Total Indirect Annual Costs	$325,180	
Total Annualized Costs	$581,347	Sum of TDAC, TEC and TIAC
	53.32	Net CO Emission Reduciton
Cost Effectiveness	$10,903	per ton of CO Removed
	$11,744	Net Emission Reduction

Table 4-7: Maximum Potential Incremental Emissions (TPY) with Selective Catalytic Reduction

Pollutants		Incremental Emissions (TPY) of SCR		
		Primary	Secondary	Total
Particulate		2.12	0.05	2.17
Sulfur Dioxide			0.02	0.02
Nitrogen Oxides			0.99	0.99
Carbon Monoxide		-53.32	0.59	-52.72
Volatile Organic Compounds			0.04	0.04
Ammonia		0.00		0.00
	Total:	-51.20	1.69	-49.50
Carbon Dioxide (additonal from gas firing)			939.10	939.10

Table 5-1: Summary of 8-Hour O_3 Measurements in Vicinity of the FPL Fort Myers Plant, 2010 to 2012

		Measurement Period		Concentration (µg/m³) 8-Hour	
Site No.	Location	Year	Months	Highest	4th Highest[a]
Ozone AAQS				**NA**	**157**
012-071-2002	5505 Rose Garden Rd	2012	Jan-Dec	129.6	127.6
	Cape Corel, FL 33914	2011	Jan-Dec	131.5	121.7
		2010	Jan-Dec	139.4	127.6
		3-Yr Average			125.6

Note: NA = not applicable.
AAQS = ambient air quality standard.

[a] The 8-hour O_3 standard is met when the 3-year average of the annual 4th highest of the daily concentration is less than 157 µg/m³.

Source: FDEP Quicklook Reports, 2010-2012.

Table 5-2: Summary of Maximum $PM_{2.5}$ Measurements in Vicinity of the FPL Fort Myers Plants, 2010 to 2

				Concentration (μg/m³)		
				24-Hour		Annual [b]
		Measurement Period			8-Hour	
Site No.	**Location**	**Year**	**Months**	**Highest**	**Highest**	**Mean**
				NA	**NA**	**12**
	Ozone AAQS					
012-071-0005	Princeton Street	2012	Jan-Dec	15.1	14.9	6.7
	Fort Myers Beach, FL	2011	Jan-Dec	25.8	15.0	7.2
		2010	Jan-Dec	21.5	14.0	7.0
		3-Yr Average				6.9

Note: NA = not applicable.
AAQS = ambient air quality standard.

[a] The 24-hour $PM_{2.5}$ standard is met when the 3-year average of the 98th percentile of the daily values is less than 35 μg/m³.

[b] The annual $PM_{2.5}$ standard is met when the 3-year average of the annual mean values is less than 12 μg/m³.

Source: FDEP Quicklook Reports, 2010-2012.

Table 5-3: Summary of 1-Hour NO_2 Measurements in Vicinity of the FPL Fort Myers Plant, 2010 to 2012

		Measurement Period		Concentration (µg/m³) 1-Hour			Annual
Site No.	Location	Year	Months	Highest	2nd Highest	98th Percentile[a]	Average
NO_2 AAQS				**NA**	**NA**	**188.1**	**100**
012-115-1006	4570 17th Street	2012	Jan-Dec	54.5	43.3	32.0	NA
	Sarasota, FL	2011	Jan-Dec	32.0	32.0	30.1	NA
		2010	Jan-Dec	56.4	48.9	45.1	NA
		3-Yr Average				35.7	NA

Note: NA = not applicable.
AAQS = ambient air quality standard.

[a] The 1-hour NO_2 standard is met when the 3-year average of the 98th percentile of the daily 1-hour maximum values is less than 188.1 µg/m³.

Source: FDEP Quicklook Reports, 2010-2012.

Golder Associates

Table 6-1: Summary of the NO_2 Facilities Considered for Inclusion in the 1-Hour NAAQS Analysis

Facility ID	Facility Description	East (km)	North (km)	Relative to Fort Myers Facility [a] X (km)	Y (km)	Distance (km)	Direction (deg)	Potential NO_x Emissions (TPY)	Include in Modeling Analysis ? [b]
Modeling Area (0km - 10km) [a]									
0710002	FLORIDA POWER & LIGHT (PFM) FORT MYERS POWER PLANT	422.3	2,952.9	0.0	0.0	0.00	0	2,600	YES
0710119	LEE COUNTY DEPT. OF SOLID WASTE MGT. LEE CO. SOLID WASTE RESOURCE REC. FAC.	424.2	2,945.7	2.3	-7.4	7.79	163	950	YES
Beyond Modeling Area (10km - 25km) [a]									
0710133	WASTE MANAGEMENT INC. OF FLORIDA GULF COAST SANITARY LANDFILL	424.2	2942.8	2.4	-10.3	10.55	167	23	NO
0150028	AJAX PAVING INDUSTRIES PUNTA GORDA PLANT NO. #2	422.6	2964.1	0.8	10.9	10.96	4	21	NO
0710004	GULF PAVING CO GULF PAVING CO	415.2	2944.1	-6.7	-9.0	11.23	216	14	NO
7775172	BETTER ROADS, INC. PLANT NO. 7 - PUNTA GORDA	423.6	2964.0	1.7	10.8	10.95	9	14	NO
0150075	CHARLOTTE COUNTY DEPT OF PUBILC WORKS ZEMEL ROAD SOLID WASTE MANAGEMENT FACIL.	405.5	2964.0	-16.4	10.8	19.66	303	53	NO
0710265	COMMUNITY ASPHALT CORPORATION FORT MYERS PLANT	417.4	2931.1	-4.4	-22.0	22.46	191	19	NO
7774822	AJAX PAVING INDUSTRIES, INC. PLANT #4	416.9	2930.8	-5.0	-22.3	22.86	193	45	NO

Note: ND = No data, SID = Significant impact distance for the project

Fort Myers Facility East and North Coordinates (km) are: 421.9 km 2953.1 km

The significant impact distance (SID) for the project is estimated to be: 10 m

EPA recommends that sources to be modeled are expected to have a significant impact in the modeling area. Therefor only sources with 2012 actual annual emissions greater than 30 TPY were included.

[a] "Modeling Area" is the area in which the project is predicted to have a significant impact (10 km). EPA recommends that all sources within this area be modeled.

[b] Background sources with NO2 emissions >25 TPY and within 10km of the project location were included in the NAAQS Analysis.

Table 6-2: Summary of Sources Included in the 1-Hour NO_2 NAAQS Modeling Analysis

Facility ID	Facility Name / Emission Unit Description	EU ID	Modeling ID Name	UTM Location X (m)	UTM Location Y (m)	Stack Parameters Height ft	Height m	Diameter ft	Diameter m	Temperature °F	Temperature K	Velocity m/s	Stack Parameter Data Source	NO_2 Emission Rate 1-Hour (lb/hr)	1-Hour (g/sec)	Emissions Data Source
0710002	FLORIDA POWER & LIGHT (PFM) FORT MYERS POWER PLANT															
	250MW Combined Cycle Combustion Turbine (2A)	018	FM2A	422238.70	2953318.65	125	38.10	19	5.79	220	377.6	21.43	2007 Title V Renewal Application (1537-1)	65	8.19	2007 Title V Renewal Application (1537-1)
	250MW Combined Cycle Combustion Turbine (2B)	019	FM2B	422195.18	2953302.63	125	38.10	19	5.79	220	377.6	21.43		65	8.19	
	250MW Combined Cycle Combustion Turbine (2C)	020	FM2C	422152.71	2953284.01	125	38.10	19	5.79	220	377.6	21.43		65	8.19	
	250MW Combined Cycle Combustion Turbine (2D)	021	FM2D	422108.61	2953265.88	125	38.10	19	5.79	220	377.6	21.43		65	8.19	
	250MW Combined Cycle Combustion Turbine (2E)	022	FM2E	422066.33	2953248.22	125	38.10	19	5.79	220	377.6	21.43		65	8.19	
	250MW Combined Cycle Combustion Turbine (2F)	023	FM2F	422023.38	2953231.52	125	38.10	19	5.79	220	377.6	21.43		65	8.19	
	170 MW Simple Cycle Combustion Turbine #1 (3A)	027	FM3A	421884.99	2953029.18	100	30.48	20	6.10	1116	875.4	38.64		320	40.32	
	170 MW Simple Cycle Combustion Turbine #2 (3B)	028	FM3B	421903.60	2952989.57	100	30.48	20	6.10	1116	875.4	38.64		320	40.32	
0710119	LEE COUNTY DEPT. OF SOLID WASTE MGT. LEE CO. SOLID WASTE RESOURCE REC. FAC	001, 002 & 006	LCSW	424,221	2,945,902	276.0	84.12	6.2	1.89	240	388.7	28.47	October 31, 2012 PSD Application	231	29.08	October 31, 2012 PSD Application

Notes:
All emission rates are based on worst case firing fuel oil.

Table 6-3a: Maximum Concentrations Predicted for Emissions of One CT Firing Natural Gas in Simple-Cycle Operation, Fort Myers (GE 7FA.05 Units)

Natural Gas	Maximum Emission Rates for CT (lb/hr) by Operating Load and Air Temperature									Averaging Time	Maximum Predicted Concentrations (μg/m³) for CT by Operating Load and Air Temperature [a]								
	Base Load			75% Load			50% Load				Base Load			75% Load			50% Load		
	35°F	75°F	95°	35°F	75°F	95°	35°F	75°F	95°		35°F	75°F	95°	35°F	75°F	95°	35°F	75°F	95°
Generic[b]	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	Annual [c]	0.085	0.086	0.090	0.11	0.11	0.11	0.13	0.13	0.13
(10 g/s) - 3.33 g/s per CT										Annual [d]	0.053	0.053	0.056	0.07	0.07	0.07	0.08	0.08	0.08
										24-Hour [c]	0.74	0.75	0.78	0.93	0.94	0.96	1.08	0.13	1.07
										24-Hour [d]	0.47	0.48	0.50	0.60	0.61	0.62	0.71	0.71	0.70
										8-Hour [c]	1.92	1.95	2.03	2.41	2.43	2.48	2.78	2.79	2.77
										3-Hour [c]	2.31	2.34	2.41	2.76	2.78	2.83	3.11	3.12	3.10
										1-Hour [c]	2.49	2.51	2.58	2.90	2.92	2.97	3.28	3.30	3.27
										1-Hour [d]	2.06	2.09	2.17	2.53	2.56	2.61	2.89	2.91	2.88
Emissions for one CT																			
PM_{10}	10.60	10.60	10.60	10.60	10.60	10.60	10.60	10.60	10.60	Annual [c]	0.011	0.011	0.012	0.014	0.015	0.015	0.017	0.017	0.017
										24-Hour [c]	0.10	0.10	0.10	0.12	0.13	0.13	0.144	0.017	0.143
$PM_{2.5}$	10.60	10.60	10.60	10.60	10.60	10.60	10.60	10.60	10.60	Annual [d]	0.007	0.007	0.007	0.009	0.009	0.009	0.011	0.011	0.011
										24-Hour [d]	0.06	0.06	0.07	0.08	0.08	0.08	0.09	0.10	0.09
NO_x	72.00	68.06	64.32	57.00	54.10	52.00	45.22	43.22	42.11	Annual [c]	0.0768	0.074	0.073	0.0773	0.074	0.073	0.072	0.069	0.067
										1-Hour [d]	1.87	1.80	1.76	1.82	1.75	1.71	1.65	1.58	1.53
CO	35.00	33.41	31.33	28.16	26.00	24.22	23.00	22.00	22.00	8-Hour [c]	0.8476	0.8215	0.8010	0.8543	0.7967	0.7577	0.8061	0.7743	0.7679
										1-Hour [c]	1.0971	1.0586	1.0193	1.0307	0.9581	0.9053	0.9508	0.9134	0.9058

[a] Concentrations are based on highest predicted concentrations from AERMOD using five years of meteorological data for 2006 to 2010 consisting of surface and upper air data from the National Weather Service stations at Fort Myers Page Field AP and Ruskin, respectively.

[b] Pollutant concentrations were based on a modeled or generic concentration predicted using a modeled emission rate of 79.37 lb/hr (10 g/s) for 3 CTs. Pollutant-specific concentrations for 1 CT were then determined by multiplying the predicted concentration by the ratio of the pollutant-specific emission rate divided by the modeled emission rate of 10 g/s.

[c] Based on the highest concentration of any year (2006-2010).

[d] Based on highest 5-year average concentration (2006-2010).

Table 6-3b: Maximum Concentrations Predicted for Emissions of One CT Firing Ultra Low Sulfur Fuel Oil in Simple-Cycle Operation, Fort Myers (GE 7FA.05 Units)

Ultra Low-Sulfur Fuel Oil	Maximum Emission Rates for CT (lb/hr) by Operating Load and Air Temperature									Averaging	Maximum Predicted Concentrations ($\mu g/m^3$) for CT by Operating Load and Air Temperature [a]								
	Base Load			75% Load			50% Load				Base Load			75% Load			50% Load		
	35°F	75°F	95°	35°F	75°F	95°	35°F	75°F	95°	Time	35°F	75°F	95°	35°F	75°F	95°	35°F	75°F	95°
Generic[b]	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	Annual [c]	0.09	0.09	0.09	0.11	0.11	0.11	0.13	0.13	0.13
(10 g/s) - 3.33 g/s per CT										Annual [d]	0.06	0.05	0.05	0.07	0.07	0.07	0.08	0.08	0.08
										24-Hour [c]	0.78	0.74	0.77	0.94	0.92	0.94	1.12	1.11	1.13
										24-Hour [d]	0.50	0.47	0.49	0.61	0.60	0.61	0.74	0.73	0.75
										8-Hour [c]	2.02	1.93	1.99	2.45	2.40	2.45	2.89	2.87	2.91
										3-Hour [c]	2.41	2.32	2.38	2.80	2.76	2.80	3.20	3.19	3.23
										1-Hour [c]	2.58	2.49	2.55	2.94	2.90	2.94	3.41	3.38	3.44
										1-Hour [d]	2.16	2.07	2.13	2.57	2.53	2.58	3.00	2.98	3.03
Emissions for one CT																			
PM_{10}	37.1	37.1	37.1	37.1	37.1	37.1	37.1	37.1	37.1	Annual [c]	0.04	0.04	0.04	0.05	0.05	0.05	0.06	0.06	0.06
										24-Hour [c]	0.36	0.35	0.36	0.44	0.43	0.44	0.52	0.52	0.53
$PM_{2.5}$	37.1	37.1	37.1	37.1	37.1	37.1	37.1	37.1	37.1	Annual [d]	0.03	0.02	0.03	0.03	0.03	0.03	0.04	0.04	0.04
										24-Hour [d]	0.23	0.22	0.23	0.29	0.28	0.29	0.35	0.34	0.35
NO_x	370.3	369.9	349.4	295.1	291.9	277.2	229.5	224.1	213.6	Annual [c]	0.42	0.40	0.39	0.41	0.39	0.38	0.38	0.37	0.36
										1-Hour [d]	10.09	9.65	9.38	9.57	9.31	9.00	8.68	8.42	8.15
CO	71.0	73.0	70.0	58.0	56.3	54.2	46.4	46.3	45.3	8-Hour [c]	1.81	1.77	1.75	1.79	1.70	1.67	1.69	1.67	1.66
										1-Hour [c]	2.30	2.29	2.25	2.15	2.06	2.01	1.99	1.98	1.96

[a] Concentrations are based on highest predicted concentrations from AERMOD using five years of meteorological data for 2006 to 2010 consisting of surface and upper air data from the National Weather Service stations at Fort Myers Page Field AP and Ruskin, respectively.

[b] Pollutant concentrations were based on a modeled or generic concentration predicted using a modeled emission rate of 79.37 lb/hr (10 g/s) for 3 CTs. Pollutant-specific concentrations for 1 CT were then determined by multiplying the predicted concentration by the ratio of the pollutant-specific emission rate divided by the modeled emission rate of 10 g/s.

[c] Based on the highest concentration of any year (2006-2010).

[d] Based on highest 5-year average concentration (2006-2010).

Table 6-4a: Maximum Concentrations Predicted for Emissions of One CT Firing Natural Gas in Simple-Cycle Operation, Fort Myers (Siemens F5 Units)

Natural Gas

	Maximum Emission Rates for CT (lb/hr) by Operating Load and Air Temperature						Averaging		Maximum Predicted Concentrations (µg/m³) for CT by Operating Load and Air Temperature [a]					
	Base Load			40% Load		44% Load			Base Load			40% Load		44% Load
	35°F	75°F	95°	35°F	75°F	95°	Time		35°F	75°F	95°	35°F	75°F	95°
Generic [b]	79.37	79.37	79.37	79.37	79.37	79.37	Annual	c	0.08	0.08	0.08	0.14	0.13	0.13
(10 g/s) - 3.33 g/s per CT							Annual	d	0.05	0.05	0.05	0.09	0.08	0.08
							24-Hour	c	0.73	0.67	0.71	1.15	1.13	1.12
							24-Hour	d	0.46	0.43	0.45	0.76	0.75	0.74
							8-Hour	c	1.90	1.76	1.84	2.97	2.91	2.88
							3-Hour	c	2.29	2.14	2.23	3.28	3.23	3.20
							1-Hour	c	2.46	2.33	2.41	3.50	3.44	3.40
							1-Hour	d	2.04	1.89	1.98	3.07	3.02	2.99
Emissions represent one CT														
PM_{10}	9	10	9	8	8	8	Annual	c	0.009	0.010	0.009	0.014	0.013	0.013
							24-Hour	c	0.08	0.08	0.08	0.116	0.114	0.113
$PM_{2.5}$	9	10	9	8	8	8	Annual	d	0.006	0.006	0.006	0.009	0.008	0.008
							24-Hour	d	0.05	0.05	0.05	0.08	0.08	0.07
NO_x	77	79	74	42	42	42	Annual	c	0.0810	0.076	0.075	0.072	0.070	0.070
							1-Hour	d	1.98	1.88	1.85	1.63	1.60	1.58
CO	21	21	20	26	26	26	8-Hour	c	0.5021	0.4645	0.4647	0.9716	0.9545	0.9439
							1-Hour	c	0.6520	0.6168	0.6083	1.1465	1.1261	1.1136

[a] Concentrations are based on highest predicted concentrations from AERMOD using five years of meteorological data for 2006 to 2010 consisting of surface and upper air data from the National Weather Service stations at Fort Myers Page Field AP and Ruskin, respectively.

[b] Pollutant concentrations were based on a modeled or generic concentration predicted using a modeled emission rate of 79.37 lb/hr (10 g/s) for 3 CTs. Pollutant-specific concentrations for 1 CT were then determined by multiplying the predicted concentrationby the ratio of the pollutant-specific emission rate divided by the modeled emission rate of 10 g/s.

[c] Based on the highest concentration of any year (2006-2010).

[d] Based on highest 5-year average concentration (2006-2010).

Table 6-4b: Maximum Concentrations Predicted for Emissions of One CT Firing Ultra Low Sulfur Fuel Oil in Simple-Cycle Operation, Fort Myers (Siemens F5 Units)

Ultra Low-Sulfur Fuel Oil	Maximum Emission Rates for CT (lb/hr) by Operating Load and Air Temperature							Maximum Predicted Concentrations (μg/m³) for CT by Operating Load and Air Temperature [a]					
	Base Load			50% Load			Averaging	Base Load			50% Load		
	35°F	75°F	95°	35°F	75°F	95°	Time	35°F	75°F	95°	35°F	75°F	95°
Generic [b]	79.37	79.37	79.37	79.37	79.37	79.37	Annual [c]	0.08	0.08	0.08	0.12	0.12	0.13
(10 g/s) - 3.33 g/s per CT							Annual [d]	0.05	0.05	0.05	0.08	0.08	0.08
							24-Hour [c]	0.72	0.70	0.73	1.05	1.04	1.07
							24-Hour [d]	0.46	0.45	0.47	0.69	0.69	0.70
							8-Hour [c]	1.88	1.82	1.91	2.72	2.70	2.77
							3-Hour [c]	2.27	2.21	2.30	3.05	3.03	3.09
							1-Hour [c]	2.45	2.39	2.47	3.21	3.19	3.26
							1-Hour [d]	2.02	1.96	2.05	2.83	2.81	2.88
Emissions for one CT													
PM_{10}	53	52	48	37	35	33	Annual [c]	0.06	0.05	0.05	0.06	0.05	0.05
							24-Hour [c]	0.48	0.46	0.44	0.49	0.46	0.44
$PM_{2.5}$	53	52	48	37	35	33	Annual [d]	0.03	0.03	0.03	0.04	0.03	0.03
							24-Hour [d]	0.31	0.29	0.28	0.32	0.30	0.29
NO_x	378	376	353	235	228	217	Annual [c]	0.39	0.38	0.37	0.36	0.35	0.34
							1-Hour [d]	9.61	9.27	9.10	8.38	8.08	7.86
CO	49	49	46	340	331	315	8-Hour [c]	1.16	1.12	1.11	11.65	11.26	10.97
							1-Hour [c]	1.51	1.48	1.43	13.74	13.29	12.94

[a] Concentrations are based on highest predicted concentrations from AERMOD using five years of meteorological data for 2006 to 2010 consisting of surface and upper air data from the National Weather Service stations at Fort Myers Page Field AP and Ruskin, respectively.

[b] Pollutant concentrations were based on a modeled or generic concentration predicted using a modeled emission rate of 79.37 lb/hr (10 g/s) for 3 CTs. Pollutant-specific concentrations for 1 CT were then determined by multiplying the predicted concentrationby the ratio of the pollutant-specific emission rate divided by the modeled emission rate of 10 g/s.

[c] Based on the highest concentration of any year (2006-2010).

[d] Based on highest 5-year average concentration (2006-2010).

Table 6-5: Summary of Maximum Pollutant Concentrations Predicted for Natural Gas and Fuel Oil Firing, Fort Myers (3 GE 7FA.05 Units)

Pollutant	Averaging Time	Concentrations (µg/m3)				EPA Class II Significant Impact Levels (µg/m3)
		Natural Gas Modeled as 8760 Hrs/Yr	Fuel Oil Modeled as 8760 Hrs/Yr	Natural Gas Limited to 3390 Hrs/Yr	Max. 2890 Hrs/Yr Natural Gas & Max. 500 Hrs/Yr Fuel Oil[a]	
PM_{10}	Annual	0.05	0.19	0.02	0.03	1
	24-Hour	0.43	1.58	0.43	0.91	5
$PM_{2.5}$	Annual	0.03	0.12	0.01	0.02	0.3
	24-Hour	0.29	1.05	0.29	0.60	1.2
Tier 1						
NO_2	Annual	0.23	1.25	0.09	0.15	1
	1-Hour	5.6	30.3	5.6	30.3	7.52
Tier 2[b]						
NO_2	Annual	0.17	0.94	0.07	0.11	1
	1-Hour	4.5	24.2	4.5	24.2	7.52
CO	8-Hour	2.6	5.4	2.6	5.4	500
	1-Hour	3.3	6.9	3.3	6.9	2,000

Maximum Hours of Fuel Usage

Natural Gas	3390
Fuel Oil	500

[a] Maximum 24-hour impacts based on 10 hours on fuel oil firing and 14 hours of natural gas firing.

[b] Assumes 75% conversion of NO_x to NO_2 for annual and 80% converstion of NO_x to NO_2 for 1-hour.

Table 6-6: Summary of Maximum Pollutant Concentrations Predicted for Natural Gas and Fuel Oil Firing, Fort Myers (3 Siemens F5 Units)

Pollutant	Averaging Time	Concentrations (µg/m3)				EPA Class II Significant Impact Levels (µg/m3)
		Natural Gas Modeled as 8760 Hrs/Yr	Fuel Oil Modeled as 8760 Hrs/Yr	Natural Gas Limited to 3390 Hrs/Yr	Max. 2890 Hrs/Yr Natural Gas & Max. 500 Hrs/Yr Fuel Oil[a]	
PM_{10}	Annual	0.04	0.17	0.02	0.02	1
	24-Hour	0.35	1.47	0.35	0.82	5
$PM_{2.5}$	Annual	0.03	0.11	0.01	0.01	0.3
	24-Hour	0.23	0.97	0.23	0.54	1.2
Tier 1						
NO_2	Annual	0.24	1.18	0.09	0.15	1
	1-Hour	5.93	28.84	5.9	28.8	7.52
Tier 2[b]						
NO_2	Annual	0.18	0.89	0.07	0.11	1
	1-Hour	4.75	23.07	4.7	23.1	7.52
CO	8-Hour	2.9	34.9	2.9	34.9	500
	1-Hour	3.4	41.2	3.4	41.2	2,000

Maximum Hours of Fuel Usage

Natural Gas	3390
Fuel Oil	500

[a] Maximum 24-hour impacts based on 10 hours on fuel oil firing and 14 hours of natural gas firing.

[b] Assumes 75% conversion of NO_x to NO_2 for annual and 80% converstion of NO_x to NO_2 for 1-hour.

Table 6-7: Maximum Predicted 1-Hour NO_2 Impacts Compared to the NAAQS

Averaging Time and Rank	Maximum Concentration (µg/m³)			Receptor Location		NAAQS
	Total	Modeled Sources[a]	Background	UTM- East (m)	UTM- North (m)	(µg/m³)
Siemens CTs						
NO_2[a, b]						
1-Hour, 98th Percentile	81.6	45.9	35.7	422,625	2,953,580	188
GE7FA5 CTs						
NO_2[a, b]						
1-Hour, 98th Percentile	81.6	45.9	35.7	422,625	2,953,580	188

[a] Concentrations are based on concentrations predicted using 5 years of meteorological data from 2006 to 2010 of surface and upper air data from the National Weather Service stations at Fort Myers/Page Field and Ruskin, respectively.
A NO_X to NO_2 conversion factor of 80% applies based on EPA's Guideline on Air Quality Models.

[b] The 1-hour NO_2 standard is met when the 5-year average of the 98th percentile of the daily 1-hour maximum values is less than 188 µg/m³. Therefore, the 8th highest 1-hour maximum modeled concentration (from 2006 - 2010) was added to a monitoring background based on the 3-year average of the 98th percentile value of the maximum daily 1-hr NO2 monitoring values.

Table 6-8: Maximum Pollutant Concentrations at the ENP Compared to the PSD Class I Area SIL

Pollutant	Averaging Time	Maximum Concentrations[a] at ENP PSD Class I Area ($\mu g/m^3$)										PSD Class I SIL ($\mu g/m^3$)
		GE 7FA.05 CTs					Siemens F5 CTs					
		8,760 Hrs on Nat.Gas	8,760 Hrs on Fuel Oil	3,390 Hrs on Nat.Gas	2,890 Hrs Nat Gas & 500 Hrs Oil		8,760 Hrs on Nat.Gas	8,760 Hrs on Fuel Oil	3,390 Hrs on Nat.Gas	2,890 Hrs Nat Gas & 500 Hrs Oil		
NO_2	Annual	0.00	0.01	0.001	0.001	b	0.00	0.01	0.001	0.001	b	0.1
	24-Hour	0.05	0.28	0.05	0.14	c	0.05	0.27	0.05	0.14	c	--
	8-Hour	0.13	0.66	0.13	0.66		0.14	0.67	0.14	0.67		--
	3-Hour	0.27	1.40	0.27	1.40		0.29	1.42	0.29	1.42		
	1-Hour	0.43	2.25	0.43	2.25		0.43	2.22	0.43	2.22		
PM_{10}	Annual	0.001	0.00	0.000	0.001	b	0.001	0.00	0.000	0.001	b	0.2
	24-Hour	0.02	0.06	0.02	0.04	c	0.02	0.09	0.02	0.05	c	0.3
	8-Hour	0.05	0.16	0.05	0.16		0.04	0.23	0.04	0.23		--
	3-Hour	0.07	0.26	0.07	0.26		0.07	0.36	0.07	0.36		
	1-Hour	0.09	0.33	0.09	0.33		0.08	0.46	0.08	0.46		
$PM_{2.5}$	Annual	0.001	0.00	0.000	0.001	b	0.001	0.00	0.000	0.001	b	0.06
	24-Hour	0.02	0.06	0.02	0.04	c	0.02	0.09	0.02	0.05	c	0.07
	8-Hour	0.05	0.16	0.05	0.16		0.04	0.23	0.04	0.23		--
	3-Hour	0.07	0.26	0.07	0.26		0.07	0.36	0.07	0.36		
	1-Hour	0.09	0.33	0.09	0.33		0.08	0.46	0.08	0.46		
CO	Annual	0.003	0.01	0.00	0.001	b	0.00	0.01	0.00	0.001	b	--
	24-Hour	0.061	0.13	0.06	0.09	c	0.04	0.09	0.04	0.06	c	--
	8-Hour	0.155	0.32	0.16	0.32		0.09	0.22	0.09	0.22		--
	3-Hour	0.241	0.50	0.24	0.50		0.14	0.34	0.14	0.34		
	1-Hour	0.413	0.87	0.41	0.87		0.24	0.58	0.24	0.58		

SIL = Class I Significant Impact Level

[a] Concentrations are based on highest predicted concentrations from CALPUFF v5.8 using 3 years of meteorological data for 2001 to 2003.

[b] Annual concentrations based on 500 hours of fuel oil and 2890 hours of natural gas firing

[c] 24-hour concentrations based on 10 hours of fuel oil and 14 hours of natural gas firing.

Table 7-1: Examples of Reported Effects of Air Pollutants at Concentrations Below National Secondary AAQS

Pollutant	Reported Effect	Concentration ($\mu g/m^3$)	Exposure
Nitrogen Dioxide[b,c]	Respiratory stress in mice	1,917	3 hours
	Respiratory stress in guinea pigs	96 to 958	8 hours/day for 122 days
Particulates[a]	Respiratory stress, reduced respiratory disease defenses	120 PbO_3	continually for 2 months
	Decreased respiratory disease defenses in rats, same with hamsters	100 $NiCl_2$	2 hours

Sources: [a] Newman and Schreiber, 1988.
[b] Gardner and Graham, 1976.
[c] Trzeciak et al., 1977.

Table 7-2: Maximum 24-Hour Visibility Impairment Predicted for the Proposed Project at the ENP PSD Class I Area

CT Manufacturer / Fuel Type	Visibility Impairment (%) [a]			Visibility Impairment Criteria (deciview)
	2001	2002	2003	
24-Hours/Day on Natural Gas (Primary)				
3 GE7FA.05 SC CTs	0.04	0.05	0.05	0.5
3 Siemens F5 SC CTs	0.04	0.05	0.05	0.5
24-Hour/Day on ULSD Oil (Backup)				
3 GE7FA.05 SC CTs	0.12	0.20	0.18	0.5
3 Siemens F5 SC CTs	0.13	0.21	0.19	0.5
Both Fuels with ULSD Oil Limited to 10 Hours Per Day				
3 GE7FA.05 SC CTs	0.07	0.12	0.10	0.5
3 Siemens F5 SC CTs	0.08	0.12	0.11	0.5

SC CTs = Simple Cycle Combustion Turbines

[a] Values presented are 98th-percentile deciviews using CALPUFF v5.8 and CALPOST v6.221, MVISBK=8, M8_MODE=5. Background extinctions are based on FLAG 2008 and 20th best natural background values.

Table 7-3: Maximum Annual Total Nitrogen Deposition Predicted for the Proposed Project at the ENP PSD Class I Area

CT Vendor	Total Deposition (Wet & Dry) $(g/m^2/s)$	$(kg/ha/yr)^{a,c}$	Year	Deposition Analysis Threshold [b] (kg/ha/yr)
3 GE 7FA.05 SC CTs				
	2.30E-12	0.0007	2001	0.01
24-Hour/Day on ULSD Oil (Backup)	3.15E-12	0.0010	2002	0.01
	1.97E-12	0.0006	2003	0.01
3 Siemens F5 SC CTs				
	2.41E-12	0.0008	2001	0.01
Both Fuels with ULSD Oil Limited to 10 Hc	3.33E-12	0.0010	2002	0.01
	2.02E-12	0.0006	2003	0.01

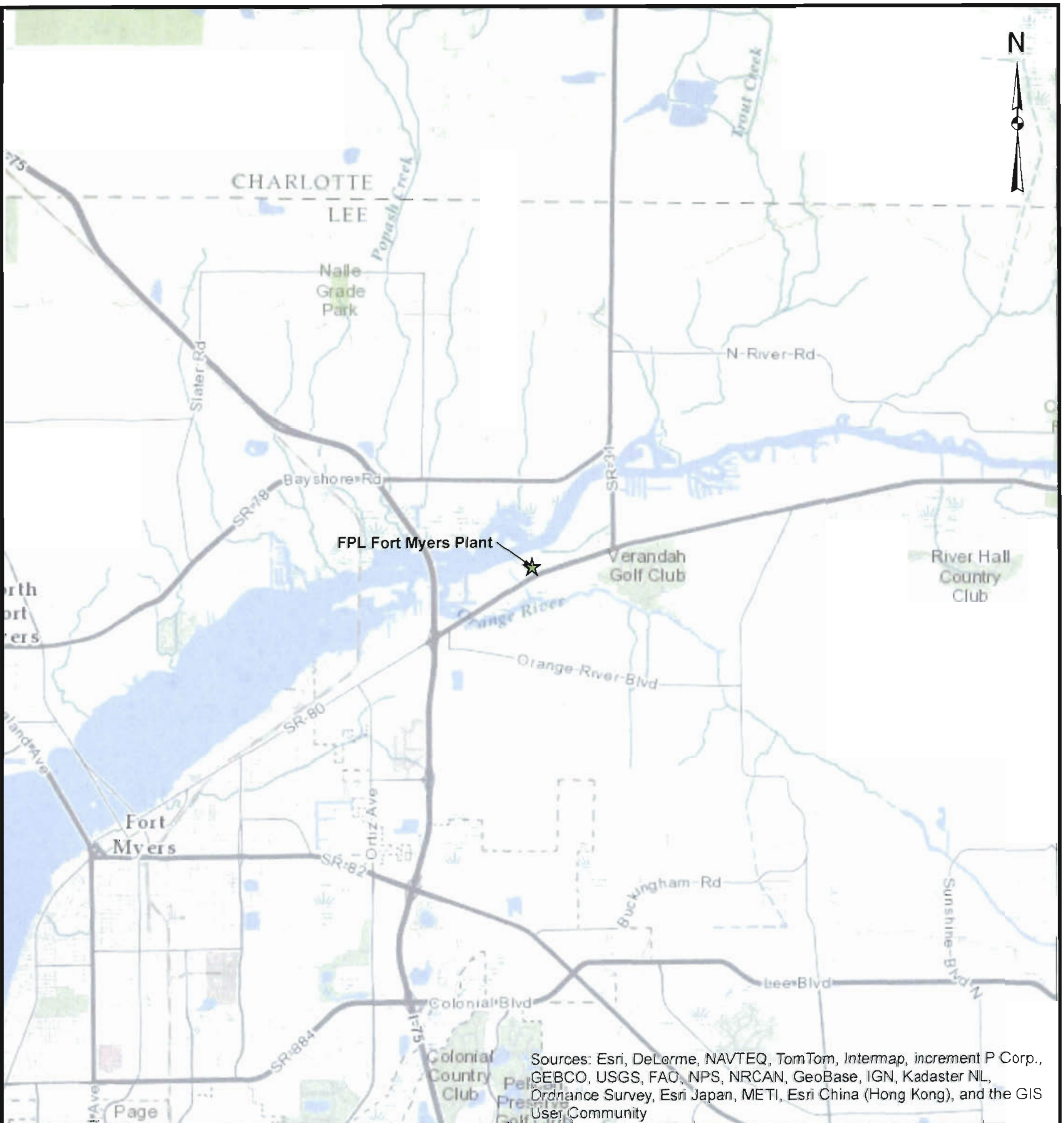
[a] Conversion factor is used to convert $g/m^2/s$ to kg/hectare (ha)/yr with the following units:

$g/m^2/s$ x 0.001 kg/g
x 10,000 m^2/hectare
x 3,600 sec/hr
x 8,760 hr/yr = kg/ha/yr
or
$g/m^2/s$ x 3.154E+08 = kg/ha/yr

[b] Deposition analysis thresholds (DAT) for nitrogen deposition provided by the U.S. Fish and Wildlife Service, January 2002. A DAT is the additional amount of nitrogen or sulfur deposition within a Class I area, below which estimated impacts from a propsed new or modified source are considered insignificant.

[c] Total nitrogen deposition is based on CTs operating 2890 hours/year on natural gas and 500 hours/year on ultra low sulfur fuel oil

FIGURES



LEGEND

☆ Project Location

10,000 0 10,000 Feet

REV	DATE	DES	REVISION DESCRIPTION	GIS	CHK	RVW
0						

PROJECT

FPL
FORT MYERS PLANT

TITLE

LOCATION MAP

REFERENCES

1 Fort Myers Plant Location, FPL and Golder Associates Inc , 2013

Coordinate System NAD 1983 StatePlane Florida East FIPS 0901 Feet
Projection. Transverse Mercator
Datum: North American 1983

Golder Associates

PROJECT No		133-87590	FILE No	13387590_B001
DESIGN	SM	16 Jul 2013	SCALE AS SHOWN	REV 0
GIS	NRL	23 Jul 2013		
CHECK	SM	23 Jul 2013	FIGURE: 1-1	
REVIEW	KFK	23 Jul 2013		

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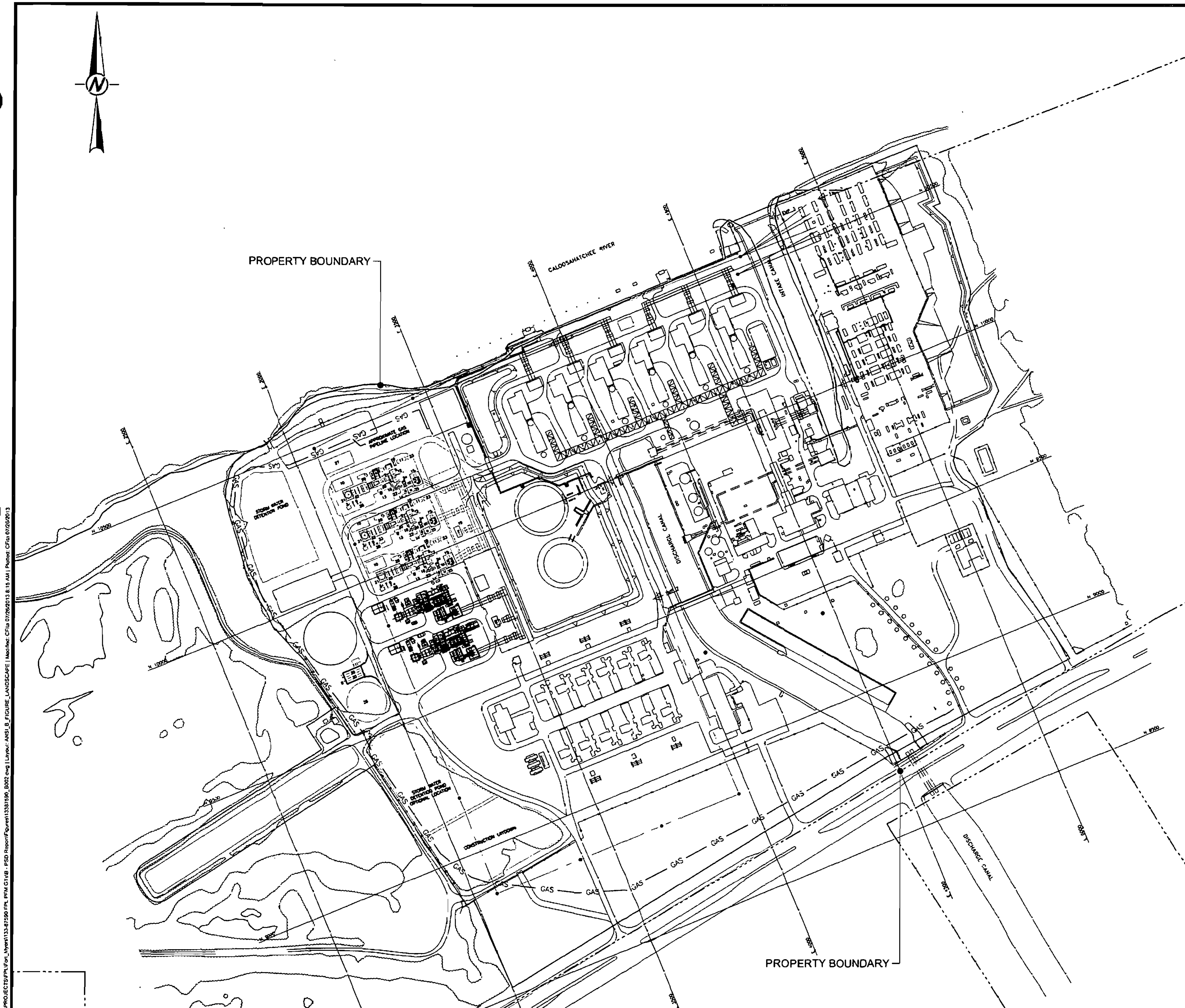
REFERENCES

DRAWING REFERENCED FROM 180321-DS2000 Layout 1 AS RECEIVED BY BLACK AND VEATCH ON JUNE 25TH, 2013

—·—·— PROPERTY BOUNDARY LINE



0 50 100 150
SCALE FEET

REV	DATE	REVISION DESCRIPTION	DES	CADD	CHK	RVW

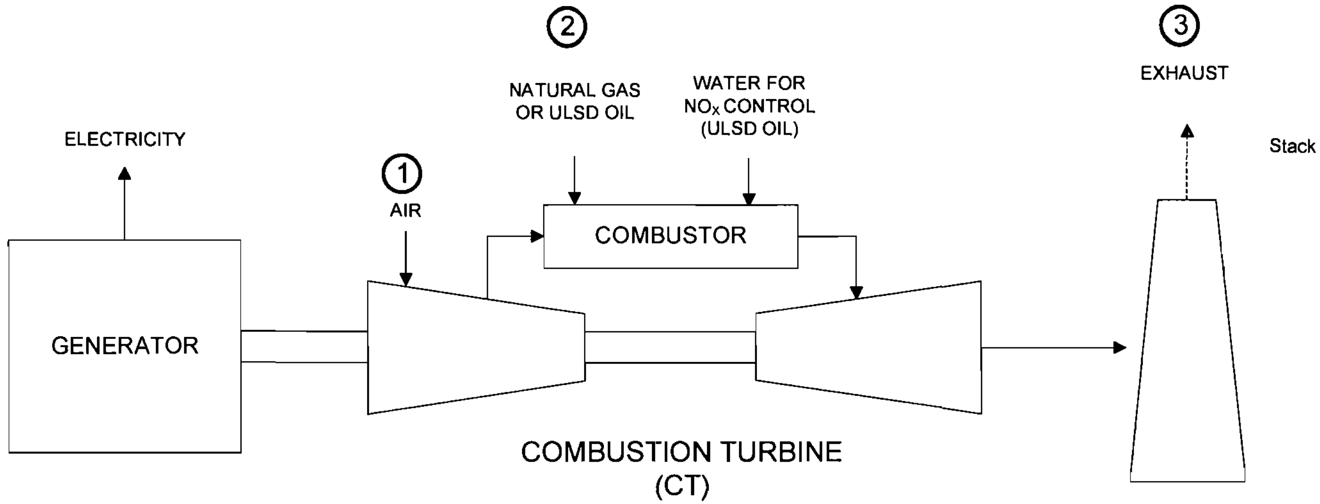
PROJECT

FPL
FT MYERS PLANT

TITLE

FACILITY PLOT PLAN

Golder Associates					
PROJECT No.		13387590	FILE No.		13387590_B002
DESIGN	N/A	7/16/13	SCALE		AS SHOWN
CADD	CF	07/16/13	FIGURE		
CHECK	NRL	07/16/13			2 - 1
REVIEW	SM	07/16/13			



	Parameters	Units	Fuel	GE 7FA.05	Siemens F5
①	Inlet Air (at 75°F)	lb/hr	Gas	4,130,000	4,576,438
		lb/hr	Oil	4,198,000	4,649,675
②	CT Heat Input	MMBtu/hr (HHV)	Gas	2,090	2,297
		MMBtu/hr (HHV)	Oil	2,260	2,193
③	Stack Velocity	ft/sec	Gas	112.6	124
		ft/sec	Oil	114	121.5
③	Stack Temperature	°F	Gas	1,117	1,108
		°F	Oil	1,106	1,067
③	Stack Height	feet	Gas/Oil	100.5	100.5
③	Stack Diameter	feet	Gas/Oil	23	23

Figure 2-2. Process Flow Diagram for Each CT
Baseload Operation, Turbine Inlet Temperature of 75°F
FPL Myers CT Project, Lee County, Florida

Source: GE, 2013; Siemens, 2013; Golder, 2013.

Process Flow Legend
Solid/Liquid
Gas
Steam

Golder Associates

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APPENDIX A

EXPECTED PERFORMANCE AND EMISSION INFORMATION FOR GE 7FA.05 CTS AND GE 7FA.04 CTS

Table GE-A-1: Design Information and Stack Parameters- Simple Cycle Operation (GE 7FA.05) Dry Low NO_x Combustor, Natural Gas

Parameter	CT Only								
	Base Load Turbine Inlet Temperature			75% Load Turbine Inlet Temperature			50% Load Turbine Inlet Temperature		
	35° F	75° F	95° F	35° F	75° F	95° F	35° F	75° F	95° F
Combustion Turbine Performance									
Heat Input (MMBtu/hr, LHV)	1,990.3	1,883.1	1,779.0	1,570.1	1,497.0	1,430.9	1,250.6	1,196.3	1,166.1
Heat Input (MMBtu/hr, HHV)	2,209.2	2,090.2	1,974.7	1,742.8	1,661.7	1,588.3	1,388.2	1,327.9	1,294.4
Evaporative Cooler	None	None	None	None	None	None	None	None	None
Relative Humidity (%)	60	60	60	60	60	60	60	60	60
Fuel heating value (Btu/lb, LHV)	21,515	21,515	21,515	21,515	21,515	21,515	21,515	21,515	21,515
Fuel heating value (Btu/lb, HHV)	23,879	23,879	23,879	23,879	23,879	23,879	23,879	23,879	23,879
Ratio of fuel heating values (HHV/LHV)	1.110	1.110	1.110	1.110	1.110	1.110	1.110	1.110	1.110
CT Exhaust Flow									
Volume flow (acfm) = [Mass flow (lb/hr) x 1545.4 x Temp (°F + 460 K)] / [2112.5 x 60 min/hr x MW] (see note below for constants)									
Mass Flow (lb/hr)	4,278,000	4,130,000	3,913,000	3,450,000	3,208,000	3,033,000	2,758,000	2,704,000	2,712,000
Temperature (°F)	1,098	1,117	1,132	1,109	1,174	1,209	1,202	1,215	1,215
Moisture (% Vol.)	8.05	9.16	10.62	7.89	9.34	10.89	7.87	8.95	10.23
Oxygen (% Vol.)	12.40	12.34	12.09	12.58	12.15	11.79	12.61	12.58	12.53
Molecular Weight	28.42	28.30	28.13	28.44	28.29	28.12	28.44	28.31	28.16
Volume flow (acfm)	2,859,044	2,806,249	2,699,692	2,320,884	2,259,352	2,195,150	1,965,032	1,950,402	1,966,615
Fuel Usage									
Fuel usage (lb/hr) = Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu [Fuel Heat Content, Btu/lb (LHV)]									
Heat Input (MMBtu/hr, LHV)	1,990.3	1,883.1	1,779.0	1,570.1	1,497.0	1,430.9	1,250.6	1,196.3	1,166.1
Heat Content (Btu/lb, LHV)	21,515	21,515	21,515	21,515	21,515	21,515	21,515	21,515	21,515
Fuel Usage (lb/hr)	92,508	87,525	82,686	72,977	69,579	66,507	58,127	55,603	54,199
Heat Content (Btu/cf, LHV)	918	918	918	918	918	918	918	918	918
Fuel Density (lb/ft^3)	0.0427	0.0427	0.0427	0.0427	0.0427	0.0427	0.0427	0.0427	0.0427
Fuel Usage (cf/hr)	2,168,083	2,051,307	1,937,908	1,710,349	1,630,719	1,558,715	1,362,309	1,303,159	1,270,261
CT Stack Parameters									
Stack Height (feet)	100.5	100.5	100.5	100.5	100.5	100.5	100.5	100.5	100.5
Stack Diameter (feet)	23	23	23	23	23	23	23	23	23
CT Stack Flow Conditions									
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)² /4) x 3.14159] / 60 sec/mir									
Stack Temperature (°F)	1,098	1,117	1,132	1,109	1,174	1,209	1,202	1,215	1,215
Volume flow (acfm)	2,859,044	2,806,249	2,699,692	2,320,884	2,259,352	2,195,150	1,965,032	1,950,402	1,966,615
Diameter (feet)	23	23	23	23	23	23	23	23	23
Velocity (ft/sec)- calculated	114.7	112.6	108.3	93.1	90.6	88.1	78.8	78.2	78.9

Note: Universal gas constant = 1,545.4 ft-lb(force)/°R; atmospheric pressure = 2,112.5 lb(force)/ft² (@14.67 psia).

Source: General Electric Company, 2013

Table GE-A-2: Maximum Emissions for Criteria Pollutants - Simple Cycle Operation (GE 7FA.05) Dry Low NO_x Combustor, Natural Gas

Parameter	CT Only: Base Load Turbine Inlet Temperature 35° F	75° F	95° F	75% Load Turbine Inlet Temperature 35° F	75° F	95° F	50% Load Turbine Inlet Temperature 35° F	75° F	95° F
Particulate Matter (PM10/PM2.5)									
$PM_{10}/PM_{2.5}$ (lb/hr) = PM_{10} Emissions Rate (lb/MMBtu) x Heat Input (MMBtu/hr, HHV) (front-half & back-half)									
PM_{10} Emission Rate (lb/MMBtu, HHV)	0.00480	0.00507	0.00537	0.00608	0.00638	0.00667	0.00764	0.00798	0.00819
Heat Input (MMBtu/hr, HHV)	2,209.2	2,090.2	1,974.7	1,742.8	1,661.7	1,588.3	1,388.2	1,327.9	1,294.4
$PM_{10}/PM_{2.5}$ Emission Rate (lb/hr)	10.6	10.6	10.6	10.6	10.6	10.6	10.6	10.6	10.6
	NA	9.4	NA	NA	NA	NA	NA	NA	NA
Sulfur Dioxide (SO_2)									
SO_2 (lb/hr)= Natural gas (scf/hr) x sulfur content(gr/100 scf) x 1 lb/7000 gr x (lb SO_2 /lb S) /100									
Fuel Use (scf/hr)	2,168,083	2,051,307	1,937,908	1,710,349	1,630,719	1,558,715	1,362,309	1,303,159	1,270,261
Sulfur Content (grains/ 100 cf)	2	2	2	2	2	2	2	2	2
lb SO_2 /lb S (64/32)	2	2	2	2	2	2	2	2	2
SO_2 Emission Rate (lb/hr)	12.4	11.7	11.1	9.8	9.3	8.9	7.8	7.4	7.3
SO_2 (lb/hr)= SO_2 Emissions Rate (lb/MMBtu) x Heat Input (MMBtu/hr, HHV)									
SO_2 Emission Rate (lb/MMBtu)	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060
Heat Input (MMBtu/hr, HHV)	2,209.2	2,090.2	1,974.7	1,742.8	1,661.7	1,588.3	1,388.2	1,327.9	1,294.4
SO_2 Emission Rate (lb/hr)	13.2	12.5	11.8	10.5	10.0	9.5	8.3	8.0	7.8
Nitrogen Oxides (No_x)									
NO_x (ppmv actual) = NO_x (ppmd @ 15%O_2) x [(20.9 - O_2 dry)/(20.9 - 15)] x [1- Moisture(%)/100]									
Oxygen (%, dry)(O_2 dry) = Oxygen (%)/[1-Moisure (%)]									
NO_x (lb/hr) = NO_x (ppm actual) x Volume flow (acfm) x 46 (mole. wgt NO_x) x 2112.5 lb/ft^2 (pressure) / [1545.4 ft-lb (gas constant, R) x Actual Temp. (°R)] x 60 min/hr									
Basis, ppm actual	10.4	10.1	10.1	10.2	10.4	10.4	10.1	9.8	9.5
NO_x, ppmvd @15% O_2 (15 ppmvd)	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
Moisture (%)	8.05	9.16	10.62	7.89	9.34	10.89	7.87	8.95	10.23
Oxygen (%)	12.40	12.34	12.09	12.58	12.15	11.79	12.61	12.58	12.53
Oxygen (%) dry	13.49	13.58	13.53	13.66	13.40	13.23	13.69	13.82	13.96
Flow (acfm)	2,859,044	2,806,249	2,699,692	2,320,884	2,259,352	2,195,150	1,965,032	1,950,402	1,966,615
Flow (acfm), dry	2,628,891	2,549,197	2,412,985	2,137,766	2,048,329	1,956,098	1,810,384	1,775,841	1,765,431
Exhaust Temperature (°F)	1,098	1,117	1,132	1,109	1,174	1,209	1,202	1,215	1,215
NO_x Emission Rate (lb/hr)	72.0	68.1	64.3	56.8	54.1	51.7	45.2	43.2	42.1
	72.0	68.0	64.0	57.0	54.0	52.0	45.0	43.0	42.0
NO_x (lb/hr) = NO_x Emissions Rate (lb/MMBtu) x Heat Input (MMBtu/hr, HHV)									
NO_x Emission Rate (lb/MMBtu)	0.03259	0.03253	0.03241	0.03271	0.03250	0.03274	0.03242	0.03238	0.03245
Heat Input (MMBtu/hr, HHV)	2209.2	2090.2	1974.7	1742.8	1661.7	1588.3	1388.2	1327.9	1294.4
NO_x Emission Rate (lb/hr)	72.0	68.0	64.0	57.0	54.0	52.0	45.0	43.0	42.0
Carbon Monoxide (CO)									
CO (ppmv wet or actual) = CO (ppmvd @ 15%O_2) x [(20.9 - O_2 dry)/(20.9 - 15)] x [1- Moisture(%)/100]									
Oxygen (%, dry)(O_2 dry) = Oxygen (%)/[1-Moisure (%)]									
CO (lb/hr) = CO (ppm actual) x Volume flow (acfm) x 28 (mole. wgt CO) x 2112.5 lb/ft^2 (pressure) / [1545.4 ft-lb (gas constant, R) x Actual Temp. (°R)] x 60 min/hr									
Basis, ppm actual	8.28	8.18	8.04	8.29	8.16	8.02	8.29	8.19	8.08
Basis, ppmvd	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
Basis, ppmvd @ 15% O_2	7.16	7.26	7.20	7.33	7.08	6.92	7.36	7.50	7.65
Moisture (%)	8.05	9.16	10.62	7.89	9.34	10.89	7.87	8.95	10.23
Oxygen (%)	12.40	12.34	12.09	12.58	12.15	11.79	12.61	12.58	12.53
Oxygen (%) dry	13.49	13.58	13.53	13.66	13.40	13.23	13.69	13.82	13.96
Flow (acfm)	2,859,044	2,806,249	2,699,692	2,320,884	2,259,352	2,195,150	1,965,032	1,950,402	1,966,615
Flow (acfm), dry	2,628,891	2,549,197	2,412,985	2,137,766	2,048,329	1,956,098	1,810,384	1,775,841	1,765,431
Exhaust Temperature (°F)	1,098	1,117	1,132	1,109	1,174	1,209	1,202	1,215	1,215
CO Emission Rate (lb/hr)	34.9	33.4	31.3	28.2	25.9	24.2	22.5	21.9	21.8
	35.0	33.0	31.0	28.0	26.0	24.0	23.0	22.0	22.0
CO (lb/hr) = CO Emissions Rate (lb/MMBtu) x Heat Input (MMBtu/hr, HHV)									
CO Emission Rate (lb/MMBtu)	0.01584	0.01579	0.01570	0.01607	0.01565	0.01511	0.01657	0.01657	0.01700
Heat Input (MMBtu/hr, HHV)	2209.2	2090.2	1974.7	1742.8	1661.7	1588.3	1388.2	1327.9	1294.4
CO Emission Rate (lb/hr)	35.0	33.0	31.0	28.0	26.0	24.0	23.0	22.0	22.0

Table GE-A-2: Maximum Emissions for Criteria Pollutants - Simple Cycle Operation (GE 7FA.05) Dry Low NO_x Combustor, Natural Gas

	CT Only								
	Base Load Turbine Inlet Temperature			75% Load Turbine Inlet Temperature			50% Load Turbine Inlet Temperature		
Parameter	35° F	75° F	95° F	35° F	75° F	95° F	35° F	75° F	95° F
Volatile Organic Compounds (VOC)									
VOC (ppmv wet or actual) = VOC (ppmvd @ 15%O_2) x [(20.9 - O_2 dry)/(20.9 - 15)] x [1- Moisture(%)/100]									
Oxygen (%, dry)(O_2 dry) = Oxygen (%)/[1-Moisure (%)]									
VOC (lb/hr) = VOC (ppm actual) x Volume flow (acfm) x 16 (mole. wgt CH_4) x 2112.5 lb/ft^2 (pressure) / [1545.4 ft-lb (gas constant, R) x Actual Temp. (°R)] x 60 min/hr									
Basis, ppm actual	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.40
Basis, ppmvd @ 15% O_2	1.02	1.03	1.00	1.05	1.00	0.96	1.06	1.06	1.07
Moisture (%)	8.05	9.16	10.62	7.89	9.34	10.89	7.87	8.95	10.23
Oxygen (%) wet	12.40	12.34	12.09	12.58	12.15	11.79	12.61	12.58	12.53
Oxygen (%) dry	13.49	13.58	13.53	13.66	13.40	13.23	13.69	13.82	13.96
Flow (acfm)	2,859,044	2,806,249	2,699,692	2,320,884	2,259,352	2,195,150	1,965,032	1,950,402	1,966,615
Flow (acfm), dry	2,628,891	2,549,197	2,412,985	2,137,766	2,048,329	1,956,098	1,810,384	1,775,841	1,765,431
Exhaust Temperature (°F)	1,098	1,117	1,132	1,109	1,174	1,209	1,202	1,215	1,215
VOC Emission Rate (lb/hr) as methane	3.37	3.27	3.12	2.72	2.54	2.42	2.17	2.14	2.16
	NA	3.3	NA	NA	NA	NA	NA	NA	NA
Sulfuric Acid Mist (SAM)									
Sulfuric Acid Mist (lb/hr)= SO_2 Emission Rate (lb/hr) x Conversion to H_2SO_4 (% by weight)/100									
SO_2 Emission Rate (lb/hr)	12.4	11.7	11.1	9.8	9.3	8.9	7.8	7.4	7.3
Conversion to H_2SO_4 (% by weight)	10	10	10	10	10	10	10	10	10
SAM Emission Rate (lb/hr)	1.2	1.2	1.1	1.0	0.9	0.9	0.8	0.7	0.7

Note: ppmvd= parts per million, volume dry; O_2= oxygen.

Source: General Electric Company, 2013

Table GE-A-3: Design Information and Stack Parameters- Simple Cycle Operation (GE 7FA.05) Dry Low NO_x Combustor, ULSD Oil Low NO_x Combustor, ULSD Oil and Natural Gas

	CT Only								
	Base Load Turbine Inlet Temperature			75% Load Turbine Inlet Temperature			50% Load Turbine Inlet Temperature		
Parameter	35° F	75° F	95° F	35° F	75° F	95° F	35° F	75° F	95° F
Combustion Turbine Performance									
Heat Input (MMBtu/hr, LHV)	2,121.3	2,121.3	2,002.9	1,691.8	1,672.7	1,589.4	1,315.7	1,285.1	1,224.0
Heat Input (MMBtu/hr, HHV)	2,260.3	2,260.3	2,134.2	1,802.7	1,782.3	1,693.6	1,401.9	1,369.3	1,304.2
Evaporative Cooler	None	None	None	None	None	None	None	None	None
Relative Humidity (%)	60	60	60	60	60	60	60	60	60
Fuel heating value (Btu/lb, LHV)	18,300	18,300	18,300	18,300	18,300	18,300	18,300	18,300	18,300
Fuel heating value (Btu/lb, HHV)	19,499	19,499	19,499	19,499	19,499	19,499	19,499	19,499	19,499
Ratio of fuel heating values (HHV/LHV)	1.066	1.066	1.066	1.066	1.066	1.066	1.066	1.066	1.066
CT Exhaust Flow									
Volume flow (acfm) = [Mass flow (lb/hr) x 1545.4 x Temp (°F + 460 K)] / [2112.5 x 60 min/hr x MW] (see note below for constants)									
Mass Flow (lb/hr)	4,040,000	4,198,000	4,028,000	3,285,000	3,233,000	3,128,000	2,627,000	2,634,000	2,586,000
Temperature (°F)	1,107	1,106	1,118	1,143	1,177	1,190	1,215	1,215	1,215
Moisture (% Vol.)	11.71	12.50	13.29	10.99	12.17	12.92	10.24	10.99	11.65
Oxygen (% Vol.)	10.53	10.70	10.68	10.82	10.57	10.58	11.17	11.24	11.34
Molecular Weight	28.31	28.20	28.10	28.37	28.24	28.15	28.44	28.34	28.25
Volume flow (acfm)	2,726,718	2,842,493	2,758,200	2,262,907	2,284,721	2,235,368	1,886,229	1,897,966	1,869,632
Fuel Usage									
Fuel usage (lb/hr) = Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu [Fuel Heat Content, Btu/lb (LHV)]									
Heat input (MMBtu/hr, LHV)	2,121.3	2,121.3	2,002.9	1,691.8	1,672.7	1,589.4	1,315.7	1,285.1	1,224.0
Heat content (Btu/lb, LHV)	18,300	18,300	18,300	18,300	18,300	18,300	18,300	18,300	18,300
Fuel usage (lb/hr)	115,918	115,918	109,448	92,448	91,404	86,852	71,896	70,224	66,885
CT Stack Parameters									
Stack Height (feet)	80	80	80	80	80	80	80	80	80
Stack Diameter (feet)	23	23	23	23	23	23	23	23	23
CT Stack Flow Conditions									
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)² /4) x 3.14159] / 60 sec/min									
Stack Temperature (°F)	1,107	1,106	1,118	1,143	1,177	1,190	1,215	1,215	1,215
Volume flow (acfm)	2,726,718	2,842,493	2,758,200	2,262,907	2,284,721	2,235,368	1,886,229	1,897,966	1,869,632
Diameter (feet)	23	23	23	23	23	23	23	23	23
Velocity (ft/sec)- calculated	109.4	114.0	110.6	90.8	91.7	89.7	75.7	76.1	75.0

Note: Universal gas constant = 1,545.4 ft-lb(force)/°R; atmospheric pressure = 2,112.5 lb(force)/ft² (@14.67 psia).

Source: General Electric Company, 2013

Table GE-A-4: Maximum Emissions for Criteria Pollutants- Simple Cycle Operation (GE 7FA.05) Dry Low NO_x Combustor, ULSD Oil Low NO_x Combustor, ULSD Oil and Natural Gas

	CT Only								
	Base Load Turbine Inlet Temperature			75% Load Turbine Inlet Temperature			50% Load Turbine Inlet Temperature		
Parameter	35° F	75° F	95° F	35° F	75° F	95° F	35° F	75° F	95° F
Particulate Matter (PM10/PM2.5)									
$PM_{10}/PM_{2.5}$ (lb/hr) = PM_{10} Emissions Rate (lb/MMBtu) x Heat Input (MMBtu/hr, HHV) (front-half & back-half)									
PM_{10} Emission Rate (lb/MMBtu, HHV)	0.01641	0.01641	0.01738	0.02058	0.02082	0.02191	0.02646	0.02709	0.02845
Heat Input (MMBtu/hr, HHV)	2,260.3	2,260.3	2,134.2	1,802.7	1,782.3	1,693.6	1,401.9	1,369.3	1,304.2
$PM_{10}/PM_{2.5}$ Emission Rate (lb/hr)	37.1	37.1	37.1	37.1	37 1	37.1	37.1	37.1	37.1
	NA	37.1	NA	NA	NA	NA	NA	NA	NA
Sulfur Dioxide (SO_2)									
SO_2 (lb/hr)= Fuel oil (lb/hr) x sulfur content(% weight) x (lb SO_2 /lb S) /100									
Fuel oil Sulfur Content	0.0015%	0.0015%	0.0015%	0.0015%	0.0015%	0.0015%	0.0015%	0.0015%	0.0015%
Fuel oil use (lb/hr)	115,918	115,918	109,448	92,446	91,404	86,852	71,896	70,224	66,885
lb SO_2 / lb S (64/32)	2	2	2	2	2	2	2	2	2
SO_2 Emission Rate (lb/hr)	3.48	3.5	3.3	2.77	2.7	2.6	2.16	2.1	2.0
SO_2 (lb/hr) = SO_2 Emissions Rate (lb/MMBtu) x Heat Input (MMBtu/hr, HHV)									
SO_2 Emission Rate (lb/MMBtu) (HHV)	0.001603	0.001803	0.001603	0.001603	0.001803	0.001603	0.001603	0.001603	0.001603
Heat Input (MMBtu/hr, HHV)	2,260.3	2,260.3	2,134.2	1,802.7	1,782.3	1,693.6	1,401.9	1,369.3	1,304.2
SO_2 Emission Rate (lb/hr)	3.62	3.62	3.42	2.89	2.86	2.72	2.25	2.20	2.09
Nitrogen Oxides (NO_x)									
NO_x (ppmv actual) = NO_x (ppmd @ 15%O_2) x [(20.9 - O_2 dry)/(20.9 - 15)] x [1- Moisture(%)/100]									
Oxygen (%, dry)(O_2 dry) = Oxygen (%)/[1-Moisure (%)]									
NO_x (lb/hr) = NO_x (ppm actual) x Volume flow (acfm) x 46 (mole. wgt NO_x) x 2112.5 lb/ft^2 (pressure) / [1545.4 ft-lb (gas constant, R) x Actual Temp. (°R)] x 60 min/hr									
Basis, ppm actual	56.4	54.0	53.0	55.4	55.4	54.2	54.0	52.4	50.7
NO_x, ppmvd @15% O_2	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0
Moisture (%)	11.71	12.50	13.29	10.99	12.17	12.92	10.24	10.99	11.65
Oxygen (%)	10.53	10.70	10.68	10.82	10.57	10.58	11.17	11.24	11.34
Oxygen (%) dry	11.93	12.23	12.32	12.16	12.03	12.15	12.44	12.63	12.84
Flow (acfm)	2,726,718	2,842,493	2,758,200	2,262,907	2,284,721	2,235,368	1,886,229	1,697,966	1,889,632
Flow (acfm), dry	2,407,419	2,487,181	2,391,635	2,014,213	2,006,671	1,946,559	1,693,079	1,689,380	1,651,820
Exhaust Temperature (°F)	1,107	1,106	1,118	1,143	1,177	1,190	1,215	1,215	1,215
NO_x Emission Rate (lb/hr)	370.3	369.9	349.4	295.1	291.9	277.2	229.5	224.1	213.6
	369.0	369.0	349.0	294.0	291.0	277.0	229.0	224.0	213.0
NO_x (lb/hr) = NO_x Emissions Rate (lb/MMBtu) x Heat Input (MMBtu/hr, HHV)									
NO_x Emission Rate (lb/MMBtu)	0.16325	0.16325	0.18353	0.16309	0.18327	0.16356	0.16335	0.16358	0.16332
Heat Input (MMBtu/hr, HHV)	2260.3	2260.3	2134.2	1802.7	1782.3	1693.6	1401.9	1369.3	1304.2
NO_x Emission Rate (lb/hr)	369.0	369.0	349.0	294.0	291.0	277.0	229.0	224.0	213.0

Table GE-A-4: Maximum Emissions for Criteria Pollutants- Simple Cycle Operation (GE 7FA.05) Dry Low NO_x Combustor, ULSD Oil Low NO_x Combustor, ULSD Oil and Natural Gas

	CT Only								
	Base Load Turbine Inlet Temperature			75% Load Turbine Inlet Temperature			50% Load Turbine Inlet Temperature		
Parameter	35° F	75° F	95° F	35° F	75° F	95° F	35° F	75° F	95° F
Carbon Monoxide (CO)									
CO (ppmv wet or actual) = CO (ppmvd @ 15%O_2) x [(20.9 - O_2 dry)/(20.9 - 15)] x [1- Moisture(%)/100]									
Oxygen (%, dry)(O_2 dry) = Oxygen (%)/[1-Moisure (%)]									
CO (lb/hr) = CO (ppm actual) x Voluma flow (acfm) x 28 (mole. wgt CO) x 2112.5 lb/ft^2 (pressure) / [1545.4 ft-lb (gas constant, R) x Actual Temp. (°R)] x 60 min/hr									
Basis, ppm actual	17.66	17.50	17.34	17.80	17.57	17.42	17.95	17.80	17.67
Basis, ppmvd	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Basis, ppmvd @ 15% O_2	13.15	13.61	13.75	13.49	13.31	13.49	13.96	14.26	14.63
Moisture (%)	11.71	12.50	13.29	10.99	12.17	12.92	10.24	10.99	11.65
Oxygen (%)	10.53	10.70	10.68	10.82	10.57	10.58	11.17	11.24	11.34
Oxygen (%) dry	11.93	12.23	12.32	12.16	12.03	12.15	12.44	12.63	12.84
Flow (acfm)	2,726,718	2,842,493	2,758,200	2,262,907	2,284,721	2,235,368	1,886,229	1,897,966	1,869,632
Flow (acfm), dry	2,407,419	2,487,181	2,391,635	2,014,213	2,006,671	1,946,559	1,693,079	1,689,380	1,651,820
Exhaust Temperature (°F)	1,107	1,106	1,118	1,143	1,177	1,190	1,215	1,215	1,215
CO Emission Rate (lb/hr)	70.6	72.9	69.6	57.7	56.3	54.2	46.4	46.3	45.3
	71.0	73.0	70.0	58.0	56.0	54.0	46.0	46.0	45.0
CO (lb/hr) = CO Emissions Rata (lb/MMBtu) x Heat Input (MMBtu/hr, HHV)									
CO Emission Rate (lb/MMBtu)	0.03141	0.03230	0.03280	0.03217	0.03142	0.03169	0.03281	0.03359	0.03450
Heat Input (MMBtu/hr, HHV)	2,260.3	2,260.3	2,134.2	1,802.7	1,782.3	1,693.8	1,401.9	1,369.3	1,304.2
CO Emission Rate (lb/hr)	71.0	73.0	70.0	58.0	56.0	54.0	46.0	46.0	45.0
Volatile Organic Compounds (VOC)									
VOC (ppmv wet or actual) = VOC (ppmvd @ 15%O_2) x [(20.9 - O_2 dry)/(20.9 - 15)] x [1- Moisture(%)/100]									
Oxygen (%, dry)(O_2 dry) = Oxygen (%)/[1-Moisure (%)]									
VOC (lb/hr) = VOC (ppm actual) x Volume flow (acfm) x 16 (mole. wgt CH_4) x 2112.5 lb/ft^2 (pressure) / [1545.4 ft-lb (gas constant, R) x Actual Temp. (°R)] x 60 min/hr									
Basis, ppm actual	3.50	3.50	3.50	5.19	5.26	5.19	5.02	4.91	4.78
Basis, ppmvd @ 15% O_2	2.03	2.08	2.09	3.93	3.98	4.02	3.90	3.93	3.96
Moisture (%)	11.71	12.50	13.29	10.99	12.17	12.92	10.24	10.99	11.65
Oxygen (%) wet	10.53	10.70	10.68	10.82	10.57	10.58	11.17	11.24	11.34
Oxygen (%) dry	11.93	12.23	12.32	12.16	12.03	12.15	12.44	12.63	12.84
Flow (acfm)	2,726,718	2,842,493	2,758,200	2,262,907	2,284,721	2,235,366	1,886,229	1,897,986	1,869,632
Flow (acfm), dry	2,407,419	2,487,181	2,391,635	2,014,213	2,006,671	1,946,559	1,693,079	1,689,380	1,651,820
Exhaust Temperature (°F)	1,107	1,106	1,118	1,143	1,177	1,190	1,215	1,215	1,215
VOC Emission Rate (lb/hr)	7.99	8.34	8.03	9.61	9.63	9.23	7.41	7.30	7.01
	NA	8.20	NA	NA	NA	NA	NA	NA	NA
Sulfuric Acid Mist (SAM)									
Sulfuric Acid Mist (lb/hr)= SO_2 Emission Rate (lb/hr) x Conversion to H_2SO_4 (% by weight)/100									
SO_2 Emission Rate (lb/hr)	3.6	3.6	3.4	2.9	2.9	2.7	2.2	2.2	2.1
Conversion to H_2SO_4 (% by weight)	10	10	10	10	10	10	10	10	10
SAM Emission Rate (lb/hr)	0.36	0.36	0.34	0.29	0.29	0.27	0.22	0.22	0.21
Lead									
Lead (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu									
Heat Input (MMBtu/hr, HHV)	2,260.3	2,260.3	2,134.2	1,802.7	1,782.3	1,693.6	1,401.9	1,369.3	1,304.2
Emission Rate Basis (lb/10^{12} Btu)	14	14	14	14	14	14	14	14	14
Lead Emission Rate (lb/hr)	0.032	0.032	0.030	0.025	0.025	0.024	0.020	0.019	0.018

Note: ppmvd= parts per million, volume dry; O_2= oxygen.

Source: General Electric Company, 2013

Table GE-A-5: Regulated and Hazardous Air Pollutant Emission Factors and Emissions for the Combustion Turbine Firing Gas Combustion and Distillate ULSD Oil (GE 7FA.05)

	Combustion Turbine Natural Gas [a]				Combustion Turbine ULSD Oil [a]				Annual Emissions (TPY) [h]			
									Scenario 1	Scenario 2	Maximum	
Pollutant	Reference	Emission Factor (lb/MMBtu)	Units	Emission Rate (lb/hr)	Reference	Emission Factor (lb/MMBtu)	Units	Emission Rate (lb/hr)	CT NG	CT NG & FO	1 CT	3 CT
1,3-Butadiene	b,c	4.30E-07	lb/MMBtu	8.99E-04	f,c	1.60E-05	lb/MMBtu	3.62E-02	1.52E-03	1.03E-02	1.03E-02	3.10E-02
Acetaldehyde	b	4.00E-05	lb/MMBtu	8.36E-02		–	–	0.00E+00	1.42E-01	1.21E-01	1.42E-01	4.25E-01
Acrolein	b	6.40E-06	lb/MMBtu	1.34E-02		–	–	0.00E+00	2.27E-02	1.93E-02	2.27E-02	6.80E-02
Benzene	b	1.20E-05	lb/MMBtu	2.51E-02	f	5.50E-05	lb/MMBtu	1.24E-01	4.25E-02	8.73E-02	6.73E-02	2.02E-01
Ethylbenzene	b	3.20E-05	lb/MMBtu	6.69E-02		–	–	0.00E+00	1.13E-01	9.67E-02	1.13E-01	3.40E-01
Formaldehyde	d	2.03E-04	lb/MMBtu	4.23E-01	d	2.17E-04	lb/MMBtu	4.91E-01	7.18E-01	7.35E-01	7.35E-01	2.20E+00
Naphthalene	b	1.30E-06	lb/MMBtu	2.72E-03	f	3.50E-05	lb/MMBtu	7.91E-02	4.61E-03	2.37E-02	2.37E-02	7.11E-02
Polycyclic Aromatic Hydrocarbons (PAH)	b,e	2.20E-06	lb/MMBtu	4.60E-03	f,e	4.00E-05	lb/MMBtu	9.04E-02	7.79E-03	2.92E-02	2.92E-02	8.77E-02
Propylene Oxide	b,c	2.90E-05	lb/MMBtu	6.06E-02		–	–	0.00E+00	1.03E-01	8.76E-02	1.03E-01	3.08E-01
Toluene	b	3.30E-05	lb/MMBtu	6.90E-02		–	–	0.00E+00	1.17E-01	9.97E-02	1.17E-01	3.51E-01
Xylene	b	6.40E-05	lb/MMBtu	1.34E-01		–	–	0.00E+00	2.27E-01	1.93E-01	2.27E-01	6.80E-01
2-Methylnaphthalene		–	–	0.00E+00		–	–	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
3-Methylchloranthrene		–	–	0.00E+00		–	–	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
7,12-Dimethylbenz(a)anthracene		–	–	0.00E+00		–	–	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Acenaphthene		–	–	0.00E+00		–	–	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Acenaphthylene		–	–	0.00E+00		–	–	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Anthracene		–	–	0.00E+00		–	–	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Benz(a)anthracene		–	–	0.00E+00		–	–	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Benzo(a)pyrene		–	–	0.00E+00		–	–	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Benzo(b)fluoranthene		–	–	0.00E+00		–	–	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Benzo(g,h,i)perylene		–	–	0.00E+00		–	–	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Benzo(k)fluoranthene		–	–	0.00E+00		–	–	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Chrysene		–	–	0.00E+00		–	–	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Dibenzo(a,h)anthracene		–	–	0.00E+00		–	–	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Dichlorobenzene		–	–	0.00E+00		–	–	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Fluoranthene [e]		–	–	0.00E+00		–	–	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Fluorene		–	–	0.00E+00		–	–	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Hexane		–	–	0.00E+00		–	–	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Indeno(1,2,3-cd)pyrene		–	–	0.00E+00		–	–	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Phenanathrene		–	–	0.00E+00		–	–	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Pyrene		–	–	0.00E+00		–	–	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Arsenic		–	–	0.00E+00	g,c	1.10E-05	lb/MMBtu	2.49E-02	0.00E+00	6.22E-03	6.22E-03	1.86E-02
Beryllium		–	–	0.00E+00	g,c	3.10E-07	lb/MMBtu	7.01E-04	0.00E+00	1.75E-04	1.75E-04	5.26E-04
Cadmium		–	–	0.00E+00	g	4.80E-06	lb/MMBtu	1.08E-02	0.00E+00	2.71E-03	2.71E-03	8.14E-03
Chromium		–	–	0.00E+00	g	1.10E-05	lb/MMBtu	2.49E-02	0.00E+00	6.22E-03	6.22E-03	1.86E-02
Cobalt		–	–	0.00E+00		–	–	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Lead		–	–	0.00E+00	g	1.40E-05	lb/MMBtu	3.16E-02	0.00E+00	7.91E-03	7.91E-03	2.37E-02
Manganese		–	–	0.00E+00	g	7.90E-04	lb/MMBtu	1.79E+00	0.00E+00	4.46E-01	4.46E-01	1.34E+00
Mercury		–	–	0.00E+00	g	1.20E-06	lb/MMBtu	2.71E-03	0.00E+00	6.76E-04	6.78E-04	2.03E-03
Nickel		–	–	0.00E+00	g,c	4.60E-06	lb/MMBtu	1.04E-02	0.00E+00	2.60E-03	2.60E-03	7.80E-03
Selenium		–	–	0.00E+00	g,c	2.50E-05	lb/MMBtu	5.65E-02	0.00E+00	1.41E-02	1.41E-02	4.24E-02
			Total HAPs =	0.88					1.50	1.48	1.59	4.77
			Max. Individual HAP =	0.42					0.72	0.73	0.73	2.20

[a] Emissions based on:

Fuel	Natural gas	ULSD oil
Heat input (MMBtu/hr) (HHV) (Baseload at 75 °F)	2,090	2,260

[b] Emission factor from Table 3.1-3, AP-42, EPA, April 2000. For Toluene, based on EPA database.

[c] Based on the method detection limit; for the CT, based on 1/2 of the method detection limit; expected emissions are lower.

[d] Formaldehyde emission factor based on 91 ppb @15% O_2 equivalent to combustion turbine MACT limit (see Table GE-A-6)

[e] Assumed to be representative of Polycyclic Organic Matter (POM) emissions, a regulated HAP.

[f] Emission factor from Table 3.1-4, AP-42, EPA, April 2000.

[g] Emission factor from Table 3.1-5, AP-42, EPA, April 2000.

h Annual operating hours

Fuel	Scenario 1	Scenario 2
Natural Gas	3,390	2,890
ULSD Oil	0	500
Total Hours	3,390	3,390

Table GE-A-6: Maximum Formaldehyde Emissions When Firing Natural Gas and ULSD Oil (GE 7FA.05

Parameter	CT at Baseload					
	Natural Gas-Firing Turbine Inlet Temperature			ULSD Oil-Firing Turbine Inlet Temperature		
	35° F	75° F	95° F	35° F	75° F	95° F
Formaldehyde (CH_2O)						
CH_2O (lb/hr) = CH_2O (ppm actual) x Volume flow (acfm) x 30 (mole. wgt CH_2O) x 2116.8 lb/ft^2 (pressure) / [1545.7 (gas constant, R) x Actual Temp. (°R)] x 60 min/h						
CH_2O (ppm actual) = CH_2O (ppmd @ 15%O_2) x [(20.9 - O_2 dry)/(20.9 - 15)] x (1- Moisture(%)/100)						
Oxygen (%, dry)(O_2 dry) = Oxygen (%)/[1-Moisure (%)]						
Basis, ppm actual- calculated	0.105	0.102	0.102	0.122	0.117	0.115
CT, ppmvd @15% O_2	0.091	0.091	0.091	0.091	0.091	0.091
Moisture (%)	8.05	9.16	10.62	11.71	12.50	13.29
Oxygen (%)	12.40	12.34	12.09	10.53	10.70	10.68
Oxygen (%) dry	13.49	13.58	13.53	11.93	12.23	12.32
Exhaust Flow (acfm)	2,859,044	2,806,249	2,699,692	2,726,718	2,842,493	2,758,200
Exhaust Temperature (°F)	1,098	1,117	1,132	1,107	1,106	1,118
Molecular weight	28.42	28.30	28.13	28.31	28.20	28.10
CT Emission rate (lb/hr)	0.450	0.423	0.398	0.494	0.491	0.462
Heat Input (MMBtu/hr, HHV)	2,209	2,090	1,975	2,260	2,260	2,134
CT Emission rate (lb/10^{12} Btu) (HHV)	203.6	202.5	201.4	218.4	217.3	216.7
CT Emission rate (lb/10^6 Btu) (HHV)	2.04E-04	2.03E-04	2.01E-04	2.18E-04	2.17E-04	2.17E-04

Note: ppmvd= parts per million, volume dry; O_2= oxygen.

Source: General Electric Company, 2013 (CT Performance Data); Golder, 2013

Table GE-A-7: Hazardous Air Pollutant Emissions for Additional Emission Units- ULSD Oil- Firing (GE 7FA.05)

Parameter	Units	Value	Annual Emission Basis Black Start Diesel Engines
Low NO_X Combustor, ULSD Oil and Natural Gas			
Number			4
Heat Input Rate	MMBtu/hr	per unit	29
Maximum operation/yr	hours	per unit	100
Heat Input Rate/annual	MMBtu/yr	all units	11,603
HAPs [Section 112(b) of Clean Air Act]	Emission Factor [a, b]		Emissions (TPY)
Acrolein	lb/MMBtu	7.88E-06	4.57E-05
Acetaldehyde	lb/MMBtu	2.52E-05	1.46E-04
Benzene	lb/MMBtu	7.76E-04	4.50E-03
Formaldehyde	lb/MMBtu	7.89E-05	4.58E-04
Naphthalene	lb/MMBtu	1.30E-04	7.54E-04
Toluene	lb/MMBtu	2.81E-04	1.63E-03
Xylene	lb/MMBtu	1.93E-04	1.12E-03
Acenaphthene	lb/MMBtu	4.68E-06	2.72E-05
Acenaphthylene	lb/MMBtu	9.23E-06	5.35E-05
Anthracene	lb/MMBtu	1.23E-06	7.14E-06
Benzo(a)anthracene	lb/MMBtu	6.22E-07	3.61E-06
Benzo(b)fluoranthene	lb/MMBtu	1.11E-06	6.44E-06
Benzo(k)fluoranthene	lb/MMBtu	2.18E-07	1.26E-06
Benzo(g,h,i)perylene	lb/MMBtu	5.56E-07	3.23E-06
Benzo(a)pyrene	lb/MMBtu	2.57E-07	1.49E-06
Chrysene	lb/MMBtu	1.53E-06	8.88E-06
Dibenzo(a,h)anthracene	lb/MMBtu	3.46E-07	2.01E-06
Fluoanthene	lb/MMBtu	4.03E-06	2.34E-05
Fluorene	lb/MMBtu	4.47E-06	2.59E-05
Indo(1,2,3-cd)pyrene	lb/MMBtu	4.14E-07	2.40E-06
Phenanthrene	lb/MMBtu	1.05E-06	6.09E-06
Pyrene	lb/MMBtu	3.71E-06	2.15E-05
Arsenic	$lb/10^{12}$ Btu	4.0	2.32E-05
Beryllium	$lb/10^{12}$ Btu	3.0	1.74E-05
Cadmium	$lb/10^{12}$ Btu	3.0	1.74E-05
Chromium	$lb/10^{12}$ Btu	3.0	1.74E-05
Lead	$lb/10^{12}$ Btu	9.0	5.22E-05
Mercury	$lb/10^{12}$ Btu	3.0	1.74E-05
Manganese	$lb/10^{12}$ Btu	6.0	3.48E-05
Nickel	$lb/10^{12}$ Btu	3.0	1.74E-05
Selenium	$lb/10^{12}$ Btu	15.0	8.70E-05
Total HAPs =			9.13E-03
Max. Individual HAP =			4.50E-03

[a] EPA AP-42, Section 3.4, Large Stationary Diesel And All Stationary Dual-fuel Engines (October 1996)

[b] EPA AP-42, Section 1.3, Fuel Oil Combustion for metals (September 1998).

Table GE-A-8: Greenhouse Gas (GHG) Emissions GE 7FA.05, Base Loac

	Maximum Heat Input at 75 °F (MMBtu/hr)		Emission Factor [a] (lb/MMBtu)		Hourly GHG Emissions (lb/hr)		Operating Hours		Annual GHG Emissions (TPY)		CO_2e Emission Rate [b] (lb/hr)		CO_2e Emission Rate [b] (TPY)		
Pollutant	Natural Gas	ULSD Oil	Natural Gas	ULSD Oil	Natural Gas	ULSD Oil	Natural Gas	ULSD Oil	Natural Gas	ULSD Oil	Natural Gas	ULSD Oil	Natural Gas	ULSD Oil	Total
Natural Gas Only															
CO_2	2,090.2	0.0	116.9	163.0	244,257.4	0.0	3,390	0	414,016.2	0	244,257.4	0.0	414,016.2	0	414,016.2
CH_4	2,090.2	0.0	0.002204	0.006612	4.6	0.0	3,390	0	7.8	0	96.7	0.0	164.0	0	164.0
N_2O	2,090.2	0.0	0.0002204	0.001322	0.5	0.0	3,390	0	0.8	0	142.8	0.0	242.1	0	242.1
										Total	244,496.9	0.0	414,422.3	0.0	414,422.3
Natural Gas & ULSD Fuel Oil															
CO_2	2,090.2	2,260.3	116.9	163.0	244,257.4	368,451.5	2,890	500	352,951.9	92,112.9	244,257.4	368,451.5	352,951.9	92,112.9	445,064.8
CH_4	2,090.2	2,260.3	0.002204	0.006612	4.6069	14.9453	2,890	500	6.7	3.7	96.7	313.9	139.80	78.46	218.3
N_2O	2,090.2	2,260.3	0.0002204	0.001322	0.4607	2.9891	2,890	500	0.7	0.7	142.8	926.6	206.37	232	438.0
										Total	244,496.9	369,692.0	353,298.1	92,423.0	445,721.1
									Maximum Total				414,422.3	92,423.0	445,721.1

[a] Table C-2, Subpart C, 40 CFR 98. Emission factors in kg/MMBtu

Pollutant	Natural Gas	Distillate Fuel Oil
CO_2	53.02	73.96
CH_4	0.001	0.003
N_2O	0.0001	0.0006

Conversion factor from kg/MMBtu to lb/MMBtu: 2.204

[b] CH_4 and N_2O are multiplied by CO_2e factor

Pollutant	CO_{2e} Factor
CH_4	21
N_2O	310

Table GE-A-9: Greenhouse Gas (GHG) Emissions for Additional Emission Units

Emission Unit/ Pollutant	Maximum Heat Input (MMBtu/hr)	Emission Factor [a] (lb/MMBtu)	Hourly GHG Emissions (lb/hr)	Operating Hours	Annual GHG Emissions (TPY)	CO_2e Emissions Rate (TPY) [b] for Number of Units	
Black Start Diesel Engine (No. Units)						**1**	**3**
CO_2	29	163.0	4,728.4	100	236.4	236.4	709.3
CH_4	29	0.006612	0.192	100	0.010	0.20	0.6
N_2O	29	0.001322	0.038	100	0.0019	0.59	1.8
						237.2	711.6

[a] Table C-2, Subpart C, 40 CFR 98. Emission factors in kg/MMBtu

Pollutant	Natural Gas	Distillate Fuel Oil
CO_2	53.02	73.96
CH_4	0.001	0.003
N_2O	0.0001	0.0006

Conversion factor from kg/MMBtu to lb/MMBtu: 2.204

[b] CH_4 and N_2O are multiplied by CO_2e factor

Pollutant	CO_{2e} Factor
CH_4	21
N_2O	310

Table GE-A-10: Comparison of GE7FA.04 and GE7FA.05 Performance Emissions - Simple Cycle Operation (GE 7FA.04 vs GE 7FA.05) Dry Low NO_X Combustor, ULSD Oil and Natural Gas

	CT Only - ISO Conditions			
	GE7FA.04		GE7FA.05	
Parameter	Fuel Oil 59 °F	Nature Gas 59 °F	Fuel Oil 59 °F	Nature Gas 59 °F
Combustion Turbine Performance				
Heat Input (MMBtu/hr, LHV)	1,926.2	1,657.0	2,121.6	1,913.9
Heat Input (MMBtu/hr, HHV)	2,052.4	1,839.1	2,260.6	2,124.2
Evaporative Cooler	None	None	None	None
Relative Humidity (%)	60	60	60	60
Fuel heating value (Btu/lb, LHV)	18,300	21,515	18,300	21,515
Fuel heating value (Btu/lb, HHV)	19,499	23,879	19,499	23,879
Ratio of fuel heating values (HHV/LHV)	1.066	1.110	1.066	1.110
Heat Rate (Btu/kWh, LHV)	9,694	8986	9531	8828
Output (MW)	198.7	184.4	222.6	216.8
Fuel Usage				
Fuel usage (lb/hr) = Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu [Fuel Heat Content, Btu/lb (LHV)]				
Heat Input (MMBtu/hr, LHV)	1,926.2	1,657.0	2,121.6	1,913.9
Heat Content (Btu/lb, LHV)	18,300	21,515	18,300	21,515
Fuel Usage (lb/hr)	105,257	77,017	115,934	88,957
Heat Content (Btu/cf, LHV)	918	918	918	918
Fuel Density (lb/ft^3)	0.0502	0.0427	0.0502	0.0427
Fuel Usage (cf/hr)	2,098,255	1,805,031	2,311,112	2,084,870
Steady-state Emissions (ISO Conditions)				
NOx corrected to 15% O2 (ppmvd)	42	9	42	9
NOx as NO2 (lb/hr)	328	60	369	69
CO (ppmvd)	20	9	20	9
CO (lb/hr)	65	29	72	33
VOC (ppmvw)	3.5	1.4	3.5	1.4
VOC as methane (lb/hr)	7.4	2.8	8.2	3.3
PM total (assuming 15 ppmw sulfur) (lb/hr)	34	8.3	37	9.4

Source: General Electric Company, 2013

APPENDIX B

EXPECTED PERFORMANCE AND EMISSION INFORMATION FOR SIEMENS F5 CTS

Table S-B-1: Design Information and Stack Parameters- Simple Cycle Operation Low NO_x Combustion, Natural Gas Siemens F5

	CT Only					
	Base Load Turbine Inlet Temperature			40% Load Turbine Inlet Temperature		44% Load Turbine Inlet Temperature
Parameter	35°F	75°F	95°F	35°F	75°F	95°F
Combustion Turbine Performance						
Heat Input (MMBtu/hr, LHV)	2,022	2,068	1,933	1,114	1,107	1,108
Heat Input (MMBtu/hr, HHV)	2,246	2,297	2,147	1,237	1,229	1,230
Evaporative Cooler	OFF	OFF	OFF	OFF	OFF	OFF
Relative Humidity (%)	60	60	60	60	60	60
Fuel heating value (Btu/lb, LHV)	20,982	20,982	20,982	20,982	20,982	20,982
Fuel heating value (Btu/lb, HHV)	23,299	23,299	23,299	23,299	23,299	23,299
Ratio of fuel heating values (HHV/LHV)	1.110	1.110	1.110	1.110	1.110	1.110
CT Exhaust Flow						
Volume flow (acfm) = [Mass flow (lb/hr) x 1545.4 x Temp (°F + 460 K)] / [2112.5 x 60 min/hr x MW] (see note below for constants)						
Mass Flow (lb/hr)	4,287,739	4,576,438	4,278,422	2,785,192	2,732,374	2,693,628
Temperature (°F)	1,107	1,108	1,127	1,118	1,154	1,176
Moisture (% Vol.)	8.23	9.20	10.67	7.09	8.44	10.02
Oxygen (% Vol.)	12.19	12.28	12.01	13.45	13.12	12.74
Molecular Weight	28.42	28.30	28.13	28.49	28.34	28.17
Volume flow (acfm)	2,882,874	3,091,716	2,942,724	1,880,866	1,897,022	1,907,287
Fuel Usage						
Fuel usage (lb/hr) = Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu [Fuel Heat Content, Btu/lb (LHV)]						
Heat Input (MMBtu/hr, LHV)	2,022	2,068	1,933	1,114	1,107	1,108
Heat Content (Btu/lb, LHV)	20,982	20,982	20,982	20,982	20,982	20,982
Fuel Usage (lb/hr)	96,368	98,561	92,127	53,093	52,760	52,807
Heat Content (Btu/cf, LHV)	918	918	918	918	918	918
Fuel Density (lb/ft^3)	0.0438	0.0438	0.0438	0.0438	0.0438	0.0438
Fuel Usage (cf/hr)	2,202,614	2,252,723	2,105,664	1,213,508	1,205,882	1,206,972
CT Stack Parameters						
Stack Height (feet)	100.5	100.5	100.5	100.5	100.5	100.5
Stack Diameter (feet)	23	23	23	23	23	23
CT Stack Flow Conditions						
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)² /4) x 3.14159] / 60 sec/min						
Stack Temperature (°F)	1,107	1,108	1,127	1,118	1,154	1,176
Volume flow (acfm)	2,882,874	3,091,716	2,942,724	1,880,866	1,897,022	1,907,287
Diameter (feet)	23	23	23	23	23	23
Velocity (ft/sec)- calculated	115.6	124.0	118.0	75.5	76.1	76.5

Note: Universal gas constant = 1,545.4 ft-lb(force)/°R; atmospheric pressure = 2,112.5 lb(force)/ft² (@14.67 psia).

Source: Siemens, 2013

Table S-B-2: Maxiumum Emissions for Criteria Pollutants- Simple Cycle Operation Low NO_x Combustion, Natural Gas Siemens F5

Parameter	CT Only					
	Base Load Turbine Inlet Temperature			40% Load Turbine Inlet Temperature		44% Load Turbine Inlet Temperature
	35°F	75°F	95°F	35°F	75°F	95°F
Particulate Matter (PM10/PM2.5)						
$PM_{10}/PM_{2.5}$ (lb/hr) = PM Emissions Rate (lb/hr) (front-half & back-half)						
$PM_{10}/PM_{2.5}$ Emission Rate (lb/hr)	9	10	9	8	8	8
Sulfur Dioxide (SO_2)						
SO_2 (lb/hr)= Natural gas (scf/hr) x sulfur content(gr/100 scf) x 1 lb/7000 gr x (lb SO_2 /lb S) /100						
Fuel Use (scf/hr)	2,202,614	2,252,723	2,105,664	1,213,508	1,205,882	1,206,972
Sulfur Content (grains/ 100 cf)	2	2	2	2	2	2
lb SO_2 /lb S (64/32)	2	2	2	2	2	2
SO_2 Emission Rate (lb/hr)	12.6	12.9	12.0	6.9	6.9	6.9
	NA	NA	NA	NA	NA	NA
SO_2 (lb/hr)= SO_2 Emissions Rate (lb/MMBtu) x Heat Input (MMBtu/hr, HHV)						
SO_2 Emission Rate (lb/MMBtu)	0.0056	0.0056	0.0056	0.0056	0.0056	0.0056
Heat Input (MMBtu/hr, HHV)	2,246	2,297	2,147	1,237	1,229	1,230
SO_2 Emission Rate (lb/hr)	12.6	12.9	12.0	6.9	6.9	6.9
Nitrogen Oxides (No_x)						
NO_x (ppmv actual) = NO_x (ppmd @ 15%O_2) x [(20.9 - O_2 dry)/(20.9 - 15)] x [1- Moisture(%)/100]						
Oxygen (%, dry)(O_2 dry) = Oxygen (%)/[1-Moisure (%)]						
NO_x (lb/hr) = NO_x (ppm actual) x Volume flow (acfm) x 46 (mole. wgt NO_x) x 2112.5 lb/ft^2 (pressure) / [1545.4 ft-lb (gas constant, R) x Actual Temp. (°R)] x 60 min/hr						
Basis, ppm actual	10.7	10.2	10.2	9.1	9.2	9.3
NO_x, ppmvd @15% O_2 (15 ppmvd)	9	9	9	9	9	9
Moisture (%)	8.23	9.20	10.67	7.09	8.44	10.02
Oxygen (%)	12.19	12.28	12.01	13.45	13.12	12.74
Oxygen (%) dry	13.28	13.52	13.44	14.48	14.33	14.16
Flow (acfm)	2,882,874	3,091,716	2,942,724	1,880,866	1,897,022	1,907,287
Flow (acfm), dry	2,645,613	2,807,278	2,628,735	1,747,513	1,736,914	1,716,177
Exhaust Temperature (°F)	1,107	1,108	1,127	1,118	1,154	1,176
NO_x Emission Rate (lb/hr)	74.0	76.0	71.1	40.9	40.7	40.7
	77	79	74	42	42	42
NO_x (lb/hr) = NO_x Emissions Rate (lb/MMBtu) x Heat Input (MMBtu/hr, HHV)						
NO_x Emission Rate (lb/MMBtu)	0.034	0.034	0.034	0.034	0.034	0.034
Heat Input (MMBtu/hr, HHV)	2246.0	2297.0	2147.0	1237.0	1229.0	1230.0
NO_x Emission Rate (lb/hr)	77.0	79.0	74.0	42.0	42.0	42.0

Table S-B-2: Maxiumum Emissions for Criteria Pollutants- Simple Cycle Operation Low NO_x Combustion, Natural Gas Siemens F5

Parameter	CT Only					
	Base Load Turbine Inlet Temperature			40% Load Turbine Inlet Temperature		44% Load Turbine Inlet Temperature
	35°F	75°F	95°F	35°F	75°F	95°F
Carbon Monoxide (CO)						
CO (ppmv wet or actual) = CO (ppmvd @ 15%O_2) x [(20.9 - O_2 dry)/(20.9 - 15)] x [1- Moisture(%)/100]						
Oxygen (%, dry)(O_2 dry) = Oxygen (%)/[1-Moisure (%)]						
CO (lb/hr) = CO (ppm actual) x Volume flow (acfm) x 28 (mole. wgt CO) x 2112.5 lb/ft^2 (pressure) / [1545.4 ft-lb (gas constant, R) x Actual Temp. (°R)] x 60 min/hr						
Basis, ppm actual	4.74	4.54	4.52	9.10	9.18	9.25
Basis, ppmvd	NA	NA	NA	NA	NA	NA
Basis, ppmvd @ 15% O_2	4	4	4	9	9	9
Moisture (%)	8.23	9.20	10.67	7.09	8.44	10.02
Oxygen (%)	12.19	12.28	12.01	13.45	13.12	12.74
Oxygen (%) dry	13.28	13.52	13.44	14.48	14.33	14.16
Flow (acfm)	2,882,874	3,091,716	2,942,724	1,880,866	1,897,022	1,907,287
Flow (acfm), dry	2,645,613	2,807,278	2,628,735	1,747,513	1,736,914	1,716,177
Exhaust Temperature (°F)	1,107	1,108	1,127	1,118	1,154	1,176
CO Emission Rate (lb/hr)	20.0	20.6	19.2	24.9	24.8	24.8
	21	21	20	26	26	26
CO (lb/hr) = CO Emissions Rate (lb/MMBtu) x Heat Input (MMBtu/hr, HHV)						
CO Emission Rate (lb/MMBtu)	0.0093	0.0091	0.0093	0.0210	0.0212	0.0211
Heat Input (MMBtu/hr, HHV)	2246	2297	2147	1237	1229	1230
CO Emission Rate (lb/hr)	21.0	21.0	20.0	26.0	26.0	26.0
Volatile Organic Compounds (VOC)						
VOC (ppmv wet or actual) = VOC (ppmvd @ 15%O_2) x [(20.9 - O_2 dry)/(20.9 - 15)] x [1- Moisture(%)/100]						
Oxygen (%, dry)(O_2 dry) = Oxygen (%)/[1-Moisure (%)]						
VOC (lb/hr) = VOC (ppm actual) x Volume flow (acfm) x 16 (mole. wgt CH_4) x 2112.5 lb/ft^2 (pressure) / [1545.4 ft-lb (gas constant, R) x Actual Temp. (°R)] x 60 min/hr						
Basis, ppm actual	1.18	1.14	1.13	1.01	1.02	1.03
Basis, ppmvd @ 15% O_2	1	1	1	1	1	1
Moisture (%)	8.23	9.20	10.67	7.09	8.44	10.02
Oxygen (%) wet	12.19	12.28	12.01	13.45	13.12	12.74
Oxygen (%) dry	13.28	13.52	13.44	14.48	14.33	14.16
Flow (acfm)	2,882,874	3,091,716	2,942,724	1,880,866	1,897,022	1,907,287
Flow (acfm), dry	2,645,613	2,807,278	2,628,735	1,747,513	1,736,914	1,716,177
Exhaust Temperature (°F)	1,107	1,108	1,127	1,118	1,154	1,176
VOC Emission Rate (lb/hr) as methane	2.4	2.6	2.4	1.6	1.5	1.5
	3.0	3.1	2.9	1.6	1.6	1.6
Sulfuric Acid Mist (SAM)						
Sulfuric Acid Mist (lb/hr)= SO_2 Emission Rate (lb/hr) x Conversion to H_2SO_4 (% by weight)/100						
SO_2 Emission Rate (lb/hr)	12.6	12.9	12.0	6.9	6.9	6.9
Conversion to H_2SO_4 (% by weight)	10	10	10	10	10	10
SAM Emission Rate (lb/hr)	1.3	1.3	1.2	0.7	0.7	0.7

Note: ppmvd= parts per million, volume dry; O_2= oxygen.

Source: Siemens, 2013

Golder Associates

Table S-B-3: Design Information and Stack Parameters- Simple Cycle Operation Low NO_x Combustion, ULSD Oil Siemens F5

	CT Only					
	Base Load Turbine Inlet Temperature			50% Load Turbine Inlet Temperature		
Parameter	35°F	75°F	95°F	35°F	75°F	95°F
Combustion Turbine Performance						
Heat Input (MMBtu/hr, LHV)	2,077	2,056	1,930	1,285	1,251	1,190
Heat Input (MMBtu/hr, HHV)	2,216	2,193	2,059	1,371	1,334	1,270
Evaporative Cooler	OFF	OFF	OFF	OFF	OFF	OFF
Relative Humidity (%)	60	60	60	60	60	60
Fuel heating value (Btu/lb, LHV)	18,450	18,450	18,450	18,450	18,450	18,450
Fuel heating value (Btu/lb, HHV)	19,680	19,680	19,680	19,680	19,680	19,680
Ratio of fuel heating values (HHV/LHV)	1.067	1.067	1.067	1.067	1.067	1.067
CT Exhaust Flow						
Volume flow (acfm) = [Mass flow (lb/hr) x 1545.4 x Temp (°F + 460 K)] / [2112.5 x 60 min/hr x MW] (see note below for constants)						
Mass Flow (lb/hr)	4,661,093	4,649,675	4,351,240	3,234,318	3,102,143	2,953,186
Temperature (°F)	1,040	1,067	1,086	1,066	1,112	1,134
Moisture (% Vol.)	6.65	8.38	10.00	5.49	6.85	8.35
Oxygen (% Vol.)	12.64	12.35	12.03	13.59	13.25	12.97
Molecular Weight	28.77	28.58	28.40	28.84	28.70	28.53
Volume flow (acfm)	2,963,172	3,029,221	2,888,125	2,086,449	2,071,671	2,011,508
Fuel Usage						
Fuel usage (lb/hr) = Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu [Fuel Heat Content, Btu/lb (LHV)]						
Heat input (MMBtu/hr, LHV)	2,077	2,056	1,930	1,285	1,251	1,190
Heat content (Btu/lb, LHV)	18,450	18,450	18,450	18,450	18,450	18,450
Fuel usage (lb/hr)	112,575	111,436	104,607	69,648	67,805	64,499
CT Stack Parameters						
Stack Height (feet)	100.5	100.5	100.5 #	100.5	100.5	100.5
Stack Diameter (feet)	23	23	23	23	23	23
CT Stack Flow Conditions						
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)² /4) x 3.14159] / 60 sec/min						
Stack Temperature (°F)	1,040	1,067	1,086	1,066	1,112	1,134
Volume flow (acfm)	2,963,172	3,029,221	2,888,125	2,086,449	2,071,671	2,011,508
Diameter (feet)	23	23	23	23	23	23
Velocity (ft/sec)- calculated	118.9	121.5	115.9	83.7	83.1	80.7

Note: Universal gas constant = 1,545.4 ft-lb(force)/°R; atmospheric pressure = 2,112.5 lb(force)/ft² (@14.67 psia).

Source: Siemens, 2013

Table S-B-4: Maximum Emissions for Criteria Pollutants- Simple Cycle Operation Low NO_x Combustion, ULSD Oil Siemens F5

	CT Only					
	Base Load Turbine Inlet Temperature			50% Load Turbine Inlet Temperature		
Parameter	35°F	75°F	95°F	35°F	75°F	95°F
Particulate Matter (PM10/PM2.5)						
$PM_{10}/PM_{2.5}$ (lb/hr) = PM Emissions Rate (lb/hr) (front-half & back-half)						
$PM_{10}/PM_{2.5}$ Emission Rate (lb/hr)	53	52	48	37	35	33
PM10/PM2.5 (lb/hr) = PM Emissions Rate (lb/MMBtu) x Heat Input (MMBtu/hr, HHV)						
PM Emission Rate (lb/MMBtu)	0.024	0.024	0.023	0.027	0.026	0.026
Heat Input (MMBtu/hr, HHV)	2,216	2,193	2,059	1,371	1,334	1,270
$PM_{10}/PM_{2.5}$ Emission Rate (lb/hr)	53.0	52.0	48.0	37.0	35.0	33.0
Sulfur Dioxide (SO_2)						
SO_2 (lb/hr)= Fuel oil (lb/hr) x sulfur content(% weight) x (lb SO_2 /lb S) /100						
Fuel oil Sulfur Content	0.0015%	0.0015%	0.0015%	0.0015%	0.0015%	0.0015%
Fuel oil use (lb/hr)	112,575	111,436	104,607	69,648	67,805	64,499
lb SO_2 / lb S (64/32)	2	2	2	2	2	2
SO_2 Emission Rate (lb/hr)	3.38	3.3	3.1	2.09	2.0	1.9
	NA	NA	NA	NA	NA	NA
SO_2 (lb/hr) = SO_2 Emissions Rate (lb/MMBtu) x Heat Input (MMBtu/hr, HHV)						
SO_2 Emission Rate (lb/MMBtu) (HHV)	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015
Heat Input (MMBtu/hr, HHV)	2,216	2,193	2,059	1,371	1,334	1,270
SO_2 Emission Rate (lb/hr)	3.38	3.34	3.14	2.09	2.03	1.93
Nitrogen Oxides (NO_x)						
NO_x (ppmv actual) = NO_x (ppmd @ 15%O_2) x [(20.9 - O_2 dry)/(20.9 - 15)] x [1- Moisture(%)/100]						
Oxygen (%, dry)(O_2 dry) = Oxygen (%)/[1-Moisure (%)]						
NO_x (lb/hr) = NO_x (ppm actual) x Volume flow (acfm) x 46 (mole. wgt NO_x) x 2112.5 lb/ft^2 (pressure) / [1545.4 ft-lb (gas constant, R) x Actual Temp. (°R)] x 60 min/hr						
Basis, ppm actual	48.9	48.4	48.3	43.9	44.3	44.0
NO_x, ppmvd @15% O_2	42	42	42	42	42	42
Moisture (%)	6.65	8.38	10.00	5.49	6.85	8.35
Oxygen (%)	12.64	12.35	12.03	13.59	13.25	12.97
Oxygen (%) dry	13.54	13.48	13.37	14.38	14.22	14.15
Flow (acfm)	2,963,172	3,029,221	2,888,125	2,086,449	2,071,671	2,011,508
Flow (acfm), dry	2,766,121	2,775,372	2,599,313	1,971,903	1,929,762	1,843,547
Exhaust Temperature (°F)	1,040	1,067	1,086	1,066	1,112	1,134
NO_x Emission Rate (lb/hr)	364.5	362.2	340.2	226.3	220.1	209.6
	378	376	353	235	228	217
NO_x (lb/hr) = NO_x Emissions Rate (lb/MMBtu) x Heat Input (MMBtu/hr, HHV)						
NO_x Emission Rate (lb/MMBtu) (HHV)	0.171	0.171	0.171	0.171	0.171	0.171
Heat Input (MMBtu/hr, HHV)	2,216	2,193	2,059	1,371	1,334	1,270
NO_x Emission Rate (lb/hr)	378	376	353	235	228	217

Table S-B-4: Maximum Emissions for Criteria Pollutants- Simple Cycle Operation Low NO_x Combustion, ULSD Oil
Siemens F5

	CT Only					
	Base Load Turbine Inlet Temperature			50% Load Turbine Inlet Temperature		
Parameter	35°F	75°F	95°F	35°F	75°F	95°F
Carbon Monoxide (CO)						
CO (ppmv wet or actual) = CO (ppmvd @ 15%O_2) x [(20.9 - O_2 dry)/(20.9 - 15)] x [1- Moisture(%)/100]						
Oxygen (%, dry)(O_2 dry) = Oxygen (%)/[1-Moisure (%)]						
CO (lb/hr) = CO (ppm actual) x Volume flow (acfm) x 28 (mole. wgt CO) x 2112.5 lb/ft^2 (pressure) / [1545.4 ft-lb (gas constant, R) x Actual Temp. (°R)] x 60 min/hr						
Basis, ppm actual	10.48	10.37	10.34	104.45	105.40	104.83
Basis, ppmvd	NA	NA	NA	NA	NA	NA
Basis, ppmvd @ 15% O_2	9	9	9	100	100	100
Moisture (%)	6.65	8.38	10.00	5.49	6.85	8.35
Oxygen (%)	12.64	12.35	12.03	13.59	13.25	12.97
Oxygen (%) dry	13.54	13.48	13.37	14.38	14.22	14.15
Flow (acfm)	2,963,172	3,029,221	2,888,125	2,086,449	2,071,671	2,011,508
Flow (acfm), dry	2,766,121	2,775,372	2,599,313	1,971,903	1,929,762	1,843,547
Exhaust Temperature (°F)	1,040	1,067	1,086	1,066	1,112	1,134
CO Emission Rate (lb/hr)	47.5	47.2	44.4	328.0	319.0	303.8
	49.0	49.0	46.0	340.0	331.0	315.0
CO (lb/hr) = CO Emissions Rate (lb/MMBtu) x Heat Input (MMBtu/hr, HHV)						
CO Emission Rate (lb/MMBtu)	0.022	0.022	0.022	0.248	0.248	0.248
Heat Input (MMBtu/hr, HHV)	2,216	2,193	2,059	1,371	1,334	1,270
CO Emission Rate (lb/hr)	49	49	46	340	331	315
Volatile Organic Compounds (VOC)						
VOC (ppmv wet or actual) = VOC (ppmvd @ 15%O_2) x [(20.9 - O_2 dry)/(20.9 - 15)] x [1- Moisture(%)/100]						
Oxygen (%, dry)(O_2 dry) = Oxygen (%)/[1-Moisure (%)]						
VOC (lb/hr) = VOC (ppm actual) x Volume flow (acfm) x 16 (mole. wgt CH_4) x 2112.5 lb/ft^2 (pressure) / [1545.4 ft-lb (gas constant, R) x Actual Temp. (°R)] x 60 min/hr						
Basis, ppm actual	NA	NA	NA	NA	NA	NA
Basis, ppmvd @ 15% O_2	1	1	1	20	20	20
Moisture (%)	6.65	8.38	10.00	5.49	6.85	8.35
Oxygen (%) wet	12.64	12.35	12.03	13.59	13.25	12.97
Oxygen (%) dry	13.54	13.48	13.37	14.38	14.22	14.15
Flow (acfm)	2,963,172	3,029,221	2,888,125	2,086,449	2,071,671	2,011,508
Flow (acfm), dry	2,766,121	2,775,372	2,599,313	1,971,903	1,929,762	1,843,547
Exhaust Temperature (°F)	1,040	1,067	1,086	1,066	1,112	1,134
VOC Emission Rate (lb/hr)	2.59	2.60	2.45	35.88	34.59	33.12
	3.1	3.1	2.9	39.0	37.9	36.1
Sulfuric Acid Mist (SAM)						
Sulfuric Acid Mist (lb/hr)= SO_2 Emission Rate (lb/hr) x Conversion to H_2SO_4 (% by weight)/100						
SO_2 Emission Rate (lb/hr)	3.4	3.3	3.1	2.1	2.0	1.9
Conversion to H_2SO_4 (% by weight)	10	10	10	10	10	10
SAM Emission Rate (lb/hr)	0.34	0.33	0.31	0.21	0.20	0.19
Lead						
Lead (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu						
Heat Input (MMBtu/hr, HHV)	2,216	2,193	2,059	1,371	1,334	1,270
Emission Rate Basis (lb/10^{12} Btu)	14	14	14	14	14	14
Lead Emission Rate (lb/hr)	0.031	0.031	0.029	0.019	0.019	0.018

Note: ppmvd= parts per million, volume dry; O_2= oxygen.

Source: Siemens, 2013

Table S-B-5: Regulated and Hazardous Air Pollutant Emission Factors and Emissions for the Combustion Turbine Firing Gas Combustion and ULSD Oil Siemens F5

	Combustion Turbine Natural Gas [a]				Combustion Turbine ULSD Oil [a]				Annual Emissions (TPY) [h]			
									Scenario 1	Scenario 2	Maximum	
Pollutant	Reference	Emission Factor	Units	Emission Rate (lb/hr)	Reference	Emission Factor	Units	Emission Rate (lb/hr)	CT NG	CT NG & FO	1 CT	3 CT
1,3-Butadiene	b,c	4.30E-07	lb/MMBtu	9.88E-04	f,c	1.80E-05	lb/MMBtu	3.51E-02	1.67E-03	1.02E-02	1.02E-02	3.06E-02
Acetaldehyde	b	4.00E-05	lb/MMBtu	9.19E-02		--	--	0.00E+00	1.56E-01	1.33E-01	1.56E-01	4.67E-01
Acrolein	b	6.40E-06	lb/MMBtu	1.47E-02		--	--	0.00E+00	2.49E-02	2.12E-02	2.49E-02	7.48E-02
Benzene	b	1.20E-05	lb/MMBtu	2.76E-02	f	5.50E-05	lb/MMBtu	1.21E-01	4.67E-02	7.00E-02	7.00E-02	2.10E-01
Ethylbenzene	b	3.20E-05	lb/MMBtu	7.35E-02		--	--	0.00E+00	1.25E-01	1.06E-01	1.25E-01	3.74E-01
Formaldehyde	d	2.06E-04	lb/MMBtu	4.73E-01	d	2.22E-04	lb/MMBtu	4.88E-01	8.01E-01	8.05E-01	8.05E-01	2.41E+00
Naphthalene	b	1.30E-06	lb/MMBtu	2.99E-03	f	3.50E-05	lb/MMBtu	7.68E-02	5.06E-03	2.35E-02	2.35E-02	7.05E-02
Polycyclic Aromatic Hydrocarbons (PAH)	b,e	2.20E-06	lb/MMBtu	5.05E-03	f,e	4.00E-05	lb/MMBtu	8.77E-02	8.57E-03	2.92E-02	2.92E-02	6.77E-02
Propylene Oxide	b,c	2.90E-05	lb/MMBtu	6.66E-02		--	--	0.00E+00	1.13E-01	9.63E-02	1.13E-01	3.39E-01
Toluene	b	3.30E-05	lb/MMBtu	7.58E-02		--	--	0.00E+00	1.28E-01	1.10E-01	1.28E-01	3.85E-01
Xylene	b	6.40E-05	lb/MMBtu	1.47E-01		--	--	0.00E+00	2.49E-01	2.12E-01	2.49E-01	7.48E-01
2-Methylnaphthalene		--	--	0.00E+00		--	--	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
3-Methylchloranthrene		--	--	0.00E+00		--	--	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
7,12-Dimethylbenz(a)anthracene		--	--	0.00E+00		--	--	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Acenaphthene		--	--	0.00E+00		--	--	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Acenaphthylene		--	--	0.00E+00		--	--	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Anthracene		--	--	0.00E+00		--	--	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Benz(a)anthracene		--	--	0.00E+00		--	--	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Benzo(a)pyrene		--	--	0.00E+00		--	--	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Benzo(b)fluoranthene		--	--	0.00E+00		--	--	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Benzo(g,h,i)perylene		--	--	0.00E+00		--	--	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Benzo(k)fluoranthene		--	--	0.00E+00		--	--	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Chrysene		--	--	0.00E+00		--	--	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Dibenzo(a,h)anthracene		--	--	0.00E+00		--	--	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Dichlorobenzene		--	--	0.00E+00		--	--	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Fluoranthene		--	--	0.00E+00		--	--	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Fluorene		--	--	0.00E+00		--	--	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Hexane		--	--	0.00E+00		--	--	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Indeno(1,2,3-cd)pyrene		--	--	0.00E+00		--	--	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Phenenathrene		--	--	0.00E+00		--	--	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Pyrene		--	--	0.00E+00		--	--	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Arsenic		--	--	0.00E+00	g,c	1.10E-05	lb/MMBtu	2.41E-02	0.00E+00	6.03E-03	6.03E-03	1.81E-02
Beryllium		--	--	0.00E+00	g,c	3.10E-07	lb/MMBtu	6.80E-04	0.00E+00	1.70E-04	1.70E-04	5.10E-04
Cadmium		--	--	0.00E+00	g	4.80E-06	lb/MMBtu	1.05E-02	0.00E+00	2.63E-03	2.63E-03	7.89E-03
Chromium		--	--	0.00E+00	g	1.10E-05	lb/MMBtu	2.41E-02	0.00E+00	6.03E-03	6.03E-03	1.81E-02
Cobalt		--	--	0.00E+00		--	--	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Lead		--	--	0.00E+00	g	1.40E-05	lb/MMBtu	3.07E-02	0.00E+00	7.68E-03	7.68E-03	2.30E-02
Manganese		--	--	0.00E+00	g	7.90E-04	lb/MMBtu	1.73E+00	0.00E+00	4.33E-01	4.33E-01	1.30E+00
Mercury		--	--	0.00E+00	g	1.20E-06	lb/MMBtu	2.63E-03	0.00E+00	6.58E-04	6.58E-04	1.97E-03
Nickel		--	--	0.00E+00	g,c	4.60E-06	lb/MMBtu	1.01E-02	0.00E+00	2.52E-03	2.52E-03	7.57E-03
Selenium		--	--	0.00E+00	g,c	2.50E-05	lb/MMBtu	5.48E-02	0.00E+00	1.37E-02	1.37E-02	4.11E-02
			Total HAPs =	0.98					1.66	1.62	1.73	5.20
			Max. Individual HAP =	0.47					0.80	0.80	0.80	2.41

[a] Emissions based on:

Fuel	Natural gas	ULSD oil
Heat input (MMBtu/hr) (HHV) (Baseload at 75 °F)	2,297	2,193

[b] Emission factor from Table 3.1-3, AP-42, EPA, April 2000. For Toluene, based on EPA database.

[c] Based on the method detection limit; for the CT, based on 1/2 of the method detection limit; expected emissions are lower.

[d] Formaldehyde emission factor based on 91 ppb @15% O_2 equivalent to combustion turbine MACT limit (see Table GE-A-6)

[e] Assumed to be representative of Polycyclic Organic Matter (POM) emissions, a regulated HAP.

[f] Emission factor from Table 3.1-4, AP-42, EPA, April 2000.

[g] Emission factor from Table 3.1-5, AP-42, EPA, April 2000.

[h] Annual operating hours

Fuel	Scenario 1	Scenario 2
Natural Gas	3,390	2,890
ULSD Oil	0	500
Total Hours	3,390	3,390

Table S-B-6: Maximum Formaldehyde Emissions When Firing Natural Gas and ULSD Oil
Siemens F5

Parameter	CT at Baseload					
	Natural Gas-Firing Turbine Inlet Temperature			Fuel Oil-Firing Turbine Inlet Temperature		
	35°F	75°F	95°F	35° F	75° F	95° F
Formaldehyde (CH_2O)						
CH_2O (lb/hr) = CH_2O (ppm actual) x Volume flow (acfm) x 30 (mole. wgt CH_2O) x 2116.8 lb/ft^2 (pressure) / [1545.7 (gas constant, R) x Actual Temp. (°R)] x 60 min/hr						
CH_2O (ppm actual) = CH_2O (ppmd @ 15%O_2) x [(20.9 - O_2 dry)/(20.9 - 15)] x (1- Moisture(%)/100)						
Oxygen (%, dry)(O_2 dry) = Oxygen (%)/[1-Moisure (%)]						
Basis, ppm actual- calculated	0.108	0.103	0.103	0.106	0.105	0.105
CT, ppmvd @15% O_2	0.091	0.091	0.091	0.091	0.091	0.091
Moisture (%)	8.23	9.20	10.67	6.65	8.38	10.00
Oxygen (%)	12.19	12.28	12.01	12.64	12.35	12.03
Oxygen (%) dry	13.28	13.52	13.44	13.54	13.48	13.37
Exhaust Flow (acfm)	2,882,874	3,091,716	2,942,724	2,963,172	3,029,221	2,888,125
Exhaust Temperature (°F)	1,107	1,108	1,127	1,040	1,067	1,086
Molecular weight	28.42	28.30	28.13	28.77	28.58	28.40
CT Emission rate (lb/hr)	0.462	0.473	0.439	0.494	0.488	0.455
Heat Input (MMBtu/hr, HHV)	2,246	2,297	2,147	2,216	2,193	2,059
CT Emission rate (lb/10^{12} Btu) (HHV)	205.8	205.8	204.7	222.9	222.3	221.0
CT Emission rate (lb/10^6 Btu) (HHV)	2.06E-04	2.06E-04	2.05E-04	2.23E-04	2.22E-04	2.21E-04

Note: ppmvd= parts per million, volume dry; O_2= oxygen.

Source: Siemens, 2013 (CT Performance Data); Golder, 2013

Table S-B-7: Hazardous Air Pollutant Emissions for Additional Emission Units- ULSD Oil-Firing Siemens F5

Parameter	Units	Value	Annual Emission Basis Black Start Diesel Engines
Number			4
Heat Input Rate	MMBtu/hr	per unit	47
Maximum operation/yr	hours	per unit	100
Heat Input Rate/annual	MMBtu/yr	all units	18,931
HAPs [Section 112(b) of Clean Air Act]	Emission Factor [a, b]		Emissions (TPY)
Acrolein	lb/MMBtu	7.88E-06	7.46E-05
Acetaldehyde	lb/MMBtu	2.52E-05	2.39E-04
Benzene	lb/MMBtu	7.76E-04	7.35E-03
Formaldehyde	lb/MMBtu	7.89E-05	7.47E-04
Naphthalene	lb/MMBtu	1.30E-04	1.23E-03
Toluene	lb/MMBtu	2.81E-04	2.66E-03
Xylene	lb/MMBtu	1.93E-04	1.83E-03
Acenaphthene	lb/MMBtu	4.68E-06	4.43E-05
Acenaphthylene	lb/MMBtu	9.23E-06	8.74E-05
Anthracene	lb/MMBtu	1.23E-06	1.16E-05
Benzo(a)anthracene	lb/MMBtu	6.22E-07	5.89E-06
Benzo(b)fluoranthene	lb/MMBtu	1.11E-06	1.05E-05
Benzo(k)fluoranthene	lb/MMBtu	2.18E-07	2.06E-06
Benzo(g,h,i)perylene	lb/MMBtu	5.56E-07	5.26E-06
Benzo(a)pyrene	lb/MMBtu	2.57E-07	2.43E-06
Chrysene	lb/MMBtu	1.53E-06	1.45E-05
Dibenzo(a,h)anthracene	lb/MMBtu	3.46E-07	3.28E-06
Fluoanthene	lb/MMBtu	4.03E-06	3.81E-05
Fluorene	lb/MMBtu	4.47E-06	4.23E-05
Indo(1,2,3-cd)pyrene	lb/MMBtu	4.14E-07	3.92E-06
Phenanthrene	lb/MMBtu	1.05E-06	9.94E-06
Pyrene	lb/MMBtu	3.71E-06	3.51E-05
Arsenic	$lb/10^{12}$ Btu	4.0	3.79E-05
Beryllium	$lb/10^{12}$ Btu	3.0	2.84E-05
Cadmium	$lb/10^{12}$ Btu	3.0	2.84E-05
Chromium	$lb/10^{12}$ Btu	3.0	2.84E-05
Lead	$lb/10^{12}$ Btu	9.0	8.52E-05
Mercury	$lb/10^{12}$ Btu	3.0	2.84E-05
Manganese	$lb/10^{12}$ Btu	6.0	5.68E-05
Nickel	$lb/10^{12}$ Btu	3.0	2.84E-05
Selenium	$lb/10^{12}$ Btu	15.0	1.42E-04
Total HAPs =			1.49E-02
Max. Individual HAP =			7.35E-03

[a] EPA AP-42, Section 3.4, Large Stationary Diesel And All Stationary Dual-fuel Engines (October 1996)
[b] EPA AP-42, Section 1.3, Fuel Oil Combustion for metals (September 1998).

Table S-B-8: Greenhouse Gas (GHG) Emissions
Siemens F5

Pollutant	Maximum Heat Input at 75 °F (MMBtu/hr) Natural Gas	ULSD Fuel Oil	Emission Factor[a] (lb/MMBtu) Natural Gas	ULSD Fuel Oil	Hourly GHG Emissions (lb/hr) Natural Gas	ULSD Fuel Oil	Operating Hours Natural Gas	ULSD Fuel Oil	Annual GHG Emissions (TPY) Natural Gas	ULSD Fuel Oil	CO_2e Emission Rate[b] (lb/hr) Natural Gas	ULSD Fuel Oil	CO_2e Emission Rate[b] (TPY) Natural Gas	ULSD Fuel Oil	Total
Natural Gas Only															
CO_2	2,297	0.0	116.9	163.0	268,418.4	0.0	3,390	0	454,969.2	0	268,418.4	0.0	454,969.2	0	454,969.2
CH_4	2,297	0.0	0.002204	0.006612	5.1	0.0	3,390	0	8.6	0	106.3	0.0	180.2	0	180.2
N_2O	2,297	0.0	0.0002204	0.001322	0.5	0.0	3,390	0	0.9	0	156.9	0.0	266.0	0	266.0
										Total	268,681.7	0.0	455,415.4	0.0	455,415.4
Natural Gas & ULSD Fuel Oil															
CO_2	2,297	2,193.0	116.9	163.0	268,418.4	357,476.2	2,890	500	387,864.6	89,369.0	268,418.4	357,476.2	387,864.6	89,369.0	477,233.7
CH_4	2,297	2,193.0	0.002204	0.006612	5.0626	14.5001	2,890	500	7.3	3.6	106.3	304.5	153.62	76.13	229.7
N_2O	2,297	2,193.0	0.0002204	0.001322	0.5063	2.9000	2,890	500	0.7	0.7	156.9	899.0	226.78	225	451.5
										Total	268,681.7	358,679.7	388,245.0	89,669.9	477,914.9
										Maximum Total			455,415.4	89,669.9	477,914.9

[a] Table C-2, Subpart C, 40 CFR 98. Emission factors in kg/MMBtu

Pollutant	Natural Gas	ULSD Fuel Oil
CO_2	53.02	73.96
CH_4	0.001	0.003
N_2O	0.0001	0.0006

Conversion factor from kg/MMBtu to lb/MMBtu: 2.204

[b] CH_4 and N_2O are multiplied by CO_2e factor

Pollutant	CO_{2e} Factor
CH_4	21
N_2O	310

Table S-B-9: Greenhouse Gas (GHG) Emissions for Additional Emission Units
Siemens F5

Emission Unit/ Pollutant	Maximum Heat Input (MMBtu/hr)	Emission Factor [a] (lb/MMBtu)	Hourly GHG Emissions (lb/hr)	Operating Hours	Annual GHG Emissions (TPY)	CO_2e Emissions Rate (TPY) [b] for Number of Units	
Black Start Diesel Engine (No. Units)						**1**	**4**
CO_2	47	163.0	7,714.9	100	385.7	385.7	1,543.0
CH_4	47	0.006612	0.313	100	0.016	0.33	1.3
N_2O	47	0.001322	0.063	100	0.0031	0.97	3.9
						387.0	1,548.2

[a] Table C-2, Subpart C, 40 CFR 98. Emission factors in kg/MMBtu

Pollutant	Natural Gas	ULSD Fuel Oil
CO_2	53.02	73.96
CH_4	0.001	0.003
N_2O	0.0001	0.0006

Conversion factor from kg/MMBtu to lb/MMBtu: 2.204

[b] CH_4 and N_2O are multiplied by CO_2e factor

Pollutant	CO_{2e} Factor
CH_4	21
N_2O	310

APPENDIX C

HISTORICAL ACTUAL EMISSION FROM EXISTING GT UNITS 1 THROUGH 12

Table 1: PFM Annual Heat Inputs, 2008 - 2012 GTs 1-12

	Heat Input from Distillate Oil (MMBtu/yr)		Heat Input from Liquid Waste (MMBtu/yr)		Total Actual Heat Input (MMBtu/yr)		Actual Operating Hours (hr/yr)
Year	GTs 1-12	Total	GTs 1-12	Total	GTs 1-12	Total	GTs 1-12
2012	35,361	35,361	0	0	35,361	35,361	217
2011	82,732	82,732	0	0	82,732	82,732	126
2010	761,464	761,464	0	0	761,464	761,464	1,218
2009	120,088	120,088	0	0	120,088	120,088	235
2008	75,208	75,208	0	0	75,208	75,208	118

Individual Fuel Heat Input as a Percent of Total Heat Input

	Heat Input from Distillate Oil (MMBtu/yr)			Heat Input from Liquid Waste (MMBtu/yr)	
Year	GTs 1-12	Total		GTs 1-12	Total
2012	100.0%	100.0%	#	0.0%	0.0%
2011	100.0%	100.0%		0.0%	0.0%
2010	100.0%	100.0%		0.0%	0.0%
2009	100.0%	100.0%		0.0%	0.0%
2008	100.0%	100.0%		0.0%	0.0%

Note: All values are based on annual operating reports for the period 2008 - 2012.

Table 2: Annual Emissions Reported in 2008-2012 Annual Operating Reports

Year	Pollutant	GTs 1-12 (tons)	Total (tons)
2012	NO_x	10.7	10.7
	CO	0.8	0.8
	SO_2	9.8	9.8
	VOC	0.01	0.0
	PM	0.2	0.2
	PM_{10}	0.2	0.2
	SAM [a]	--	0.0
	CO_2	--	--
2011	NO_x	25.6	25.6
	CO	2.0	2.0
	SO_2	22.5	22.5
	VOC	0.02	0.0
	PM	0.5	0.5
	PM_{10}	0.5	0.5
	SAM [a]	--	--
	CO_2	--	--
2010	NO_x	269.8	269.8
	CO	18.6	18.6
	SO_2	136.6	136.6
	VOC	0.50	0.5
	PM	4.8	4.8
	PM_{10}	4.8	4.8
	SAM [a]	--	--
	CO_2	--	--
2009	NO_x	4.6	4.6
	CO	2.9	2.9
	SO_2	4.0	4.0
	VOC	0.08	0.1
	PM	0.8	0.8
	PM_{10}	0.8	0.8
	SAM [a]	--	--
	CO_2	--	--
2008	NO_x	26.7	26.7
	CO	1.8	1.8
	SO_2	13.5	13.5
	VOC	0.05	0.0
	PM	0.5	0.5
	PM_{10}	0.5	0.5
	SAM [a]	--	--
	CO_2	--	--

Source: Annual Operating Report (AOR) for PFM, 2008 - 2012.

Table 3: Actual Emissions as a Function of Heat Input, 2008 - 2012

Year	Actual Annual Heat Input (MMBtu/yr) [a]	Actual Emissions (TPY) [b]								Emissions per Unit Heat Input [c] (lb/MMBtu)							
		NO_X	CO	VOC	SO_2	PM	PM_{10}	SAM[d]	CO_2 [e]	NO_X	CO	VOC	SO_2	PM	PM_{10}	SAM	CO_2 [e]
2012	35,361	10.7	0.8	0.0	9.8	0.2	0.2	1.5	--	0.6052	0.0480	0.0004	0.5543	0.0123	0.0123	0.0849	--
2011	82,732	25.6	2.0	0.0	22.5	0.5	0.5	3.4	--	0.6189	0.0480	0.0004	0.5439	0.0123	0.0123	0.0833	--
2010	761,464	269.8	18.6	0.5	136.6	4.8	4.8	20.9	--	0.7088	0.0488	0.0013	0.3588	0.0125	0.0125	0.0549	--
2009	120,088	4.6	2.9	0.1	4.0	0.8	0.8	0.6	--	0.0766	0.0488	0.0013	0.0666	0.0125	0.0125	0.0102	--
2008	75,208	26.7	1.8	0.0	13.5	0.5	0.5	2.1	--	0.7087	0.0488	0.0013	0.3588	0.0125	0.0125	0.0549	--
									Maximum =	0.7088	0.0488	0.0013	0.5543	0.0125	0.0125	0.0849	--

[a] Based on AOR data; see Table 1.

[b] Based on AOR data; see Table 2.

[c] Total actual emissions divided by total heat input.

[d] Not reported in AORs - based on assuming 10% of SO2 converts to SO3, all of which converts to SAM.

[e] See Table 4 for CO_2 calculation.

Table 4: Estimated Actual Annual Emissions of N_2O, CH_4, and CO_2 for the Period 2008 - 2012
PFM GTs No. 1-12

Unit	Actual Annual Heat Input [a] (MMBtu/yr)	N_2O Emissions: Emission Factor [b] (lb/MMBtu)	N_2O Emissions: Annual Emissions (lb/yr)	N_2O Emissions: Annual Emissions (TPY)	N_2O Emissions: CO_2e [c] Rate (TPY)	CH_4 Emissions: Emission Factor [b] (lb/MMBtu)	CH_4 Emissions: Annual Emissions (lb/yr)	CH_4 Emissions: Annual Emissions (TPY)	CH_4 Emissions: CO_2e [c] Rate (TPY)	CO_2 Emissions: Emission Factor [d] (lb/MMBtu)	CO_2 Emissions: Annual Emissions (lb/yr)	CO_2 Emissions: Annual Emissions (TPY)
Distillate Oil												
2012	35,361	1.32E-03	46.8	2.34E-02	7.2	6.6E-03	233.8	0.1	2.5	1.6E+02	5,764,185	2,882.1
2011	82,732	1.32E-03	109.4	5.47E-02	17.0	6.6E-03	547.0	0.3	5.7	1.6E+02	13,485,982	6,743.0
2010	761,464	1.32E-03	1,007.0	5.03E-01	156.1	6.6E-03	5,034.8	2.5	52.9	1.6E+02	124,124,602	62,062.3
2009	120,088	1.32E-03	158.8	7.94E-02	24.6	6.6E-03	794.0	0.4	8.3	1.6E+02	19,575,285	9,787.6
2008	75,208	1.32E-03	99.5	4.97E-02	15.4	6.6E-03	497.3	0.2	5.2	1.6E+02	12,259,494	6,129.7
Liquid Waste												
2012	0.0	1.32E-03	0.0	0.0	0.0	6.6E-03	0.0	0.0	0.0	1.6E+02	0	0.0
2011	0.0	1.32E-03	0.0	0.0	0.0	6.6E-03	0.0	0.0	0.0	1.6E+02	0	0.0
2010	0.0	1.32E-03	0.0	0.0	0.0	6.6E-03	0.0	0.0	0.0	1.6E+02	0	0.0
2009	0.0	1.32E-03	0.0	0.0	0.0	6.6E-03	0.0	0.0	0.0	1.6E+02	0	0.0
2008	0.0	1.32E-03	0.0	0.0	0.0	6.6E-03	0.0	0.0	0.0	1.6E+02	0	0.0
Total												
2012	35,361	--	46.8	2.34E-02	7.2	--	233.8	0.1	2.5	--	5,764,185	2,882.1
2011	82,732	--	109.4	5.47E-02	17.0	--	547.0	0.3	5.7	--	13,485,982	6,743.0
2010	761,464	--	1,007.0	5.03E-01	156.1	--	5,034.8	2.5	52.9	--	124,124,602	62,062.3
2009	120,088	--	158.8	7.94E-02	24.6	--	794.0	0.4	8.3	--	19,575,285	9,787.6
2008	75,208	--	99.5	4.97E-02	15.4	--	497.3	0.2	5.2	--	12,259,494	6,129.7

[a] Based on AOR data; see Table 1.

[b] Table C-2, Subpart C, 40 CFR 98. Emission factors in kg/MMBtu were converted to lb/MMBtu by multiplying by 2.204.

[c] N_2O and CH_4 are multiplied by a factor of 310 and 21, respectively, to determine CO_2 equivalence.

[d] Table C-1, Subpart C, 40 CFR 98. Emission factors in kg/MMBtu were converted to lb/MMBtu by multiplying by 2.204.

Table 5: Annual Average Emissions for GTs No. 1-12 for Each Consecutive Two-Year Period, 2008-2012

Pollutant	Annual Emissions for GTs No. 1-12					Two-Year Average Emissions				Maximum 2-year Average (tons/yr)
	2012	2011	2010	2009	2008	2012-2011 (tons)	2011-2010 (tons)	2010-2009 (tons)	2009-2008 (tons)	
NO_x	10.7	25.6	269.8	4.6	26.7	18.2	147.7	137.2	15.6	147.7
CO	0.8	2.0	18.6	2.9	1.8	1.4	10.3	10.7	2.4	10.7
SO_2	9.8	22.5	136.6	4.0	13.5	16.2	79.6	70.3	8.7	79.6
VOC	7.7E-03	1.8E-02	5.0E-01	7.9E-02	5.0E-02	1.3E-02	2.6E-01	2.9E-01	6.5E-02	0.3
PM	0.2	0.5	4.8	0.8	0.5	0.4	2.6	2.8	0.6	2.8
PM_{10}	0.2	0.5	4.8	0.8	0.5	0.4	2.6	2.8	0.6	2.8
$PM_{2.5}$ [a]	0.2	0.5	4.8	0.8	0.5	0.4	2.6	2.8	0.6	2.8
SAM [b]	1.2	2.8	16.7	0.5	1.7	2.5	12.2	10.8	1.3	12.2
GHG [c] (CO_2e)	2891.8	6765.7	62271.2	9820.6	6150.4	4828.7	34518.5	36045.9	7985.5	36,045.9

[a] Assuming equal to PM_{10} emissions.

[b] Not reported in AORs - based on assuming 10% of SO_2 converts to SO_3, all of which converts to SAM.

[c] Calculated based on actual annual heat input - see Table 4.

Source: Annual Operating Report (AOR) for 2008 - 2012; EPA's Acid Rain database.

APPENDIX D

BACT DETERMINATIONS FOR SIMPLE CYCLE CTS

Table D-1: Summary of NO_x BACT Determinations for Natural Gas-Fired CTs (2003-2013)

Facility Name	State	Permit Issued	Process Info	Heat Input	Control Method	NO_x Limit	Basis
Florida							
JEA Greenland Energy Center	FL	3/10/2009	Turbine, Simple Cycle, Natural Gas	190 MW	DLN and WI	9 PPMVD @ 15% O2	BACT-PSD
Shady Hills Generating Station	FL	1/12/2009	Two Simple Cycle Combustion Turbine - Model 7FA	170 MW	DLN	9 PPMVD @ 15% O2	BACT-PSD
Progress Bartow Power Plant	FL	1/26/2007	Simple Cycle Combustion Turbine (1)	1972 MMBTU/H	DLN and WI	15 PPMVD	BACT-PSD
JEA- St. Johns River Park Plant	FL	12/22/2006	Simple Cycle Turbine 172 MW	1804 MMBTU/H	DLN and WI	15 PPM @ 15% O2	OTHER CASE-BY-CASE
Oleander Power Project	FL	11/17/2006	Simple Cycle Combustion Turbine	190 MW	DLN and WI	9 PPM @15% O2	BACT-PSD
TEC/Polk Power Energy Station	FL	4/28/2006	Simple Cycle Gas Turbine	1834 MMBTU/H	DLN	9 PPMVD @ 15% O2	BACT-PSD
FPL Martin Plant	FL	4/16/2003	Turbine, Simple Cycle, Natural Gas, (4)	170 MW	DLN	9 PPMVD @ 15% O2	BACT-PSD
EPA Region 4 (AL, FL, GA, KY, MS, NC, SC, TN)							
Dahlberg Combusdtion Turbine Electric Generating Facility	GA	5/14/2010	Simple Cycle Combustion Turbine - Electric Generating Plant	1530 MW	DLN And Wi	9 PPM @ 15% O2	BACT-PSD
Exxon Mobile Bay -- Northwest Gulf Field	AL	2/1/2005	Turbine, Simple Cycle	6000 BHP	Solonox Combustor	25 PPM @ 15% O2	BACT-PSD
Exxon Mobile -- Mobile Bay - Bon Secure Bay Field	AL	2/1/2005	Turbine, Simple Cycle	3600 BHP	Solonox Combustion	25 PPM @ 15% O2	BACT-PSD
TVA - Kemper Combustion Turbine Plant	MS	12/10/2004	GE Combustion Turbine (4)	1278 MMBTU/H		12 PPM @ 15% O2	BACT-PSD
Moselle Plant	MS	12/10/2004	Combustion Turbine, Gas-Fired, Simple-Cycle	1143.3 MMBTU/H	DLN Burner With Inlet Gas Cooling.	9 PPM VD @ 15% O2	BACT-PSD
Louisville Gas And Electric Company	KY	6/6/2003	Turbine, Simple Cycle, Natural Gas (6)	160 MW	DLN Combustors	12 PPM @ 15% O2	BACT-PSD
Smepa - Silver Creek Generating	MS	5/29/2003	Turbine, Simple Cycle (3)	1109.3 MMBTU/H	DLN Burners	9 PPM @ 15% O2	BACT-PSD
Other States							
NRG Marsh Landing	CA		Turbine, Simple Cycle, Natural Gas (4)	190 MW	DLN and hot SCR	2.5 PPMVD @15% O2	BACT-PSD
R.M. Heskett Station	ND	2/22/2013	Combustion Turbine	986 MMBTU/H	DLN	9 PPMVD @15% O2	BACT-PSD
Bosque County Power Plant	TX	2/27/2009	Electrical Generation	170 MW	DLN	9 PPMVD @15% O2	BACT-PSD
Great River Energy - Elk River Station	MN	7/1/2008	Combustion Turbine Generator	2169 MMBTU/H	DLN	9 PPM	BACT-PSD
Rawhide Energy Station	CO	8/31/2007	Unit F Combustion Turbine	1400 MMBTU/H	DLN	9 PPMVD	BACT-PSD
We Energies Concord	WI	1/26/2006	Combustion Turbine, 100 Mw, Natural Gas	100 MW	WI	25 PPMDV @ 15% O2	BACT-PSD
Fairbault Energy Park	MN	7/15/2004	Turbine, Simple Cycle, Natural Gas (1)	1663 MMBTU/H	DLN In Lean Premix Mode.	25 PPMVD @ 15% 02	BACT-PSD
Great River Energy Lakefield Junction Station	MN	9/10/2003	Turbine, Simple Cycle, Natural Gas	109 MW	DLN and GCP	9 PPM @ 15% O2	BACT-PSD
ODEC - Louisa Facility	VA	3/11/2003	Turbine, Simple Cycle, (1), Natural Gas	1624 MMBTU/H	GCP And CEM System.	10.5 PPMVD @ 15% O2	N/A
ODEC - Marsh Run Facility	VA	2/14/2003	Turbine, Simple Cycle, (4), Natural Gas	1624 MMBTU/H	DLN Burners	9 PPMVD @ 15% O2	N/A
ODEC -Marsh	VA	2/14/2003	Turbine, Simple Cycle, Natural Gas, (4)	1624 MMBTU/H	DLN and WI	10.5 PPMVD	BACT-PSD

Source: EPA 2013 (RBLC database); Golder, 2013

Note: DLN= dry low NOx; WI= water injection; SI=Steam Injection; GCP= good combustion practices; SCR= selective catalytic reduction

Table D-2: Summary of NO_x BACT Determinations for ULSD Oil-Fired CTs (2003-2013)

Facility Name	State	Permit Issued	Process Info	Heat Input	Fuel	Control Method	NO_x Limit	Basis
Florida								
JEA Greenland Energy Center	FL	3/10/2009	Turbine, Simple Cycle, Natural Gas	190 MW	NO.2 FUEL OIL	WI	42 PPMVD @ 15% O2	BACT-PSD
Shady Hills Generating Station	FL	1/12/2009	Two Simple Cycle Combustion Turbine - Model 7FA	170 MW	NO.2 FUEL OIL	WI	42 PPMVD @ 15% O2	BACT-PSD
FPL MARTIN PLANT	FL	12/22/2003	TURBINE, SIMPLE CYCLE, FUEL OIL (4)	170 MW	NO.2 FUEL OIL	WI	42 PPMVD @ 15% O2	BACT-PSD
EPA Region 4 (AL, FL, GA, KY, MS, NC, SC, TN)								
TVA - KEMPER COMBUSTION TURBINE PLANT	MS	1/25/2005	GENERAL ELECTRIC COMBUSTION TURBINES		NO.2 FUEL OIL	WI	42 PPMDV @ 15% O2	BACT-PSD
Talbot Energy Facility	GA	6/9/2003	Turbine, Simple Cycle, Fuel Oil, (2)	108 MW	NO.2 FUEL OIL	DLN and WI	42 PPMDV @ 15% O2	BACT-PSD
Broad River Energy Center	SC	5/22/2003	Combustion Turbines		NO.2 FUEL OIL	WI	42 PPMDV @ 15% O2	BACT-PSD
Other States								
WE ENERGIES CONCORD	WI	11/29/2006	COMBUSTION TURBINE, 100 MW, #2 FUEL OIL	100 MW	No. 2 FUEL OIL	WI	65 PPMDV @ 15% O2	BACT-PSD
FAIRBAULT ENERGY PARK	MN	9/21/2004	TURBINE, SIMPLE CYCLE, DISTILLATE OIL (1)	1576 MMBTU/H	No. 2 FUEL OIL	WI	42 PPMDV @ 15% O2	BACT-PSD
ODEC - LOUISA	VA	6/21/2004	TURBINE, SIMPLE CYCLE, FUEL OIL (1)	1820 MMBTU/H	No. 2 FUEL OIL	WI	42 PPMVD @ 15% O2	BACT-PSD
ODEC - LOUISA FACILITY	VA	4/28/2003	TURBINE, SIMPLE CYCLE, (1), FUEL OIL	1820 MMBTU/H	No. 2 FUEL OIL	GCP AND CEM SYSTEM.	42 PPMVD @ 15% O2	BACT-PSD
Great River Energy Lakefield Junction Station	MN	9/10/2003	Turbine, Simple Cycle, Fuel Oil	109 MW	No. 2 FUEL OIL	WI and GCP	42 PPMVD @ 15% O2	BACT-PSD
ODEC - Marsh Run Facility	VA	2/14/2003	Turbine, Simple Cycle, (4), Fuel Oil	1803 MMBTU/H	No. 2 FUEL OIL	DLN BURNERS, CLEAN BURNING FUEL, AND CEM SYSTEM.	62 PPMVD @ 15% O2	NA

Source: EPA 2013 (RBLC database); Golder, 2013

Note: SCR= selective catalytic reduction; WI= water injection; GCP= good combustion practices

Table D-3: Summary of CO BACT Determinations for Natural Gas-Fired CTs (2003-2013)

Facility Name	State	Permit Issued	Process Info	Heat Input	Control Method	CO Limit	Basis
Florida							
JEA Greenland Energy Center	FL	3/10/2009	TURBINE, SIMPLE CYCLE, NATURAL GAS	190 MW	GCP	4.1 PPMVD @ 15% O2	BACT-PSD
SHADY HILLS GENERATING STATION	FL	1/12/2009	TWO SIMPLE CYCLE COMBUSTION TURBINE - MODEL 7FA	170 MW	GCP	6.5 PPMVD @ 15% O2	Avoid PSD
JEA Kennedy7 Generating Station	FL	12/4/2008	TURBINE, SIMPLE CYCLE, NATURAL GAS	172 MW	GCP	9 PPMVD @ 15% O2	BACT-PSD
Orlando Utilities- Curtis H Station Energy Center	FL	5/12/2008	TURBINE, SIMPLE CYCLE, NATURAL GAS	170 MW	GCP	8 PPMVD @ 15% O2	BACT-PSD
Oleander Power Project	FL	11/17/2006	Simple Cycle Combustion Turbine	190 MW	GCP	9 PPM @15% O2	OTHER CASE-BY-CASE
TEC/Polk Power Energy Station	FL	4/28/2006	Simple Cycle Gas Turbine	1834 MMBTU/H	GCP	9 PPMVD @ 15% O2	Avoid PSD
FPL MARTIN PLANT	FL	4/16/2003	TURBINE, SIMPLE CYCLE, NATURAL GAS, (4)	170 MW	GCP	8 PPMVD @ 15% O2	BACT-PSD
EPA Region 4 (AL, FL, GA, KY, MS, NC, SC, TN)							
DAHLBERG COMBUSDTION TURBINE ELECTRIC GENERATING FACILITY	GA	5/14/2010	SIMPLE CYCLE COMBUSTION TURBINE - ELECTRIC GENERATING PLANT	1530 MW	GCP	9 PPM @ 15% O2	BACT-PSD
TVA - KEMPER COMBUSTION TURBINE PLANT	MS	12/10/2004	GENERAL ELECTRIC COMBUSTION TURBINES			20 PPM @ 15% 02	BACT-PSD
TVA - KEMPER COMBUSTION TURBINE PLANT	MS	12/10/2004	EMISSION POINT (4)	1278 MMBTU/H		25 PPM @ 15% 02	BACT-PSD
MOSELLE PLANT	MS	12/10/2004	COMBUSTION TURBINE, GAS-FIRED, SIMPLE-CYCLE	1143.3 MMBTU/H		20 PPM @ 15% 02	BACT-PSD
LOUISVILLE GAS AND ELECTRIC COMPANY	KY	6/6/2003	TURBINE, SIMPLE CYCLE, NATURAL GAS (6)	160 MW	GCP	9 PPM @ 15% 02	BACT-PSD
SMEPA - SILVER CREEK GENERATING	MS	5/29/2003	TURBINE, SIMPLE CYCLE (3)	1109.3 MMBTU/H	GCP	25 PPM @ 15% 02	BACT-PSD
Other States							
R.M. HESKETT STATION	ND	2/22/2013	Combustion Turbine	986 MMBtu/hr	GCP	25 PPMVD@15% O2	BACT-PSD
PSEG FOSSIL LLC KEARNY GENERATING STATION	NJ	10/27/2010	SIMPLE CYCLE TURBINE	8940000 MMBtu/year (HHV)	Oxidation Catalyst, GCP	5 PPMVD@15% O2	OTHER CASE-BY-CASE
HOWARD DOWN STATION	NJ	9/16/2010	SIMPLE CYCLE (NO WASTE HEAT RECOVERY)(>25 MW)	5000 MMFT3/YR	THE TURBINE WILL UTILIZE A CATALYTI	5 PPMVD@15%O2	OTHER CASE-BY-CASE
BAYONNE ENERGY CENTER	NJ	9/24/2009	COMBUSTION TURBINES, SIMPLE CYCLE , ROLLS ROYCE, 8	603 MMBTU/H	CO OXIDATION CATALYST AND CLEAN E	5 PPMVD@15%O2	OTHER CASE-BY-CASE
FAIRBAULT ENERGY PARK	MN	7/15/2004	TURBINE, SIMPLE CYCLE, NATURAL GAS (1)	1663 MMBTU/H	GCP.	10 PPMVD @ 15% O2	BACT-PSD
ODEC - LOUISA FACILITY	VA	3/11/2003	TURBINE, SIMPLE CYCLE, (4), NATURAL GAS	901 MMBTU/H	GCP AND A CONTINUOUS EMISSION MO	25 PPMVD @ 15% O2	N/A
ODEC - LOUISA FACILITY	VA	3/11/2003	TURBINE, SIMPLE CYCLE, (1), NATURAL GAS	1624 MMBTU/H	GCP AND CONTINUOUS EMISSION MON	9 PPMVD @ 15% O2	N/A

Source: EPA 2013 (RBLC database); Golder, 2013

Note: DB = duct burner; GCP= good combustion practices

Table D-4: Summary of CO BACT Determinations for ULSD Oil-Fired CTs (2003-2013)

Facility Name	State	Permit Issued	Process Info	Heat Input	Fuel	Control Method	CO Limit	Basis
Georgia								
JEA Greenland Energy Center	FL	3/10/2009	Turbine, Simple Cycle, Natural Gas	NO.2 FUEL OIL	170 MW	GCP	8 PPMVD @ 15% O2	BACT-PSD
Shady Hills Generating Station	FL	1/12/2009	Two Simple Cycle Combustion Turbine - Model 7FA	NO.2 FUEL OIL	170 MW	GCP	13.5 PPMVD @ 15% O2	BACT-PSD
FPL MARTIN PLANT	FL	4/16/2003	TURBINE, SIMPLE CYCLE, FUEL OIL (4)	NO.2 FUEL OIL	170 MW	GCP	15 PPMVD @ 15% O2	BACT-PSD
EPA Region 4 (AL, FL, GA, KY, MS, NC, SC, TN)								
TVA - KEMPER COMBUSTION TURBINE PLANT	MS	1/25/2005	GENERAL ELECTRIC COMBUSTION TURBINES	NO.2 FUEL OIL			20 PPM @ 15% O2	BACT-PSD
BROAD RIVER ENERGY CENTER	SC	12/17/2012	COMBUSTION TURBINES	NO.2 FUEL OIL		GCP AND CLEAN BURNING FUELS	20 PPMVD @ 15% O2	BACT-PSD
Other States								
FAIRBAULT ENERGY PARK	MN	7/15/2004	TURBINE, SIMPLE CYCLE, DISTILLATE OIL (1)	NO.2 FUEL OIL	1576 MMBTU/H	GCP.	10 PPMVD @ 15% O2	BACT-PSD
FAIRBAULT ENERGY PARK	MN	7/15/2004	TURBINE, COMBINED CYCLE, DISTILLATE OIL (1)	NO.2 FUEL OIL	1801 MMBTU/H	GCP.	10 PPMVD @ 15% O2	BACT-PSD
ODEC - LOUISA FACILITY	VA	3/11/2003	TURBINE, SIMPLE CYCLE, (1), FUEL OIL	NO.2 FUEL OIL	1820 MMBTU/H	GCP AND CEM SYSTEM.	20 PPMVD @ 15% O2	N/A
LSP Nelson Energy, LLC	IL	1/28/2000	CT, CC w/ Duct Burner	NO.2 FUEL OIL	2166 MMBtu/hr	GCP and Combustion Controls	0.1024 lb/MMBtu	

Source: EPA 2013 (RBLC database); Golder, 2013

Note: GCP= good combustion practices

Table D-5: Summary of VOC BACT Determinations for Natural Gas-Fired CTs (2003-2013)

Facility Name	State	Permit Issued	Process Info	Fuel	Heat Input	Control Method	VOC Limit	Basis
Georgia								
Progress Bartow Power Plant	FL	1/26/2007	Simple Cycle Combustion Turbine (1)	NATURAL GAS	1972 MMBTU/H	GCP	1.2 PPMVD	BACT-PSD
FPL Martin Plant	FL	4/16/2003	Turbine, Simple Cycle, Natural Gas, (4)	NATURAL GAS	170 MW	GCP	1.3 PPMVD @ 15% O2	BACT-PSD
EPA Region 4 (AL, FL, GA, KY, MS, NC, SC, TN)								
Dahlberg Combusdtion Turbine Electric Generating Fac	GA	5/14/2010	Simple Cycle Combustion Turbine - Electric Generating Plant	NATURAL GAS	1530 MW	GCP	5 PPM@15%02	BACT-PSD
TVA - Kemper Combustion Turbine Plant	MS	12/10/2004	GE Combustion Turbine (4)	NATURAL GAS	1278 MMBTU/H		70 LB/H	
Talbot Energy Facility	GA	6/9/2003	Turbine, Simple Cycle, Natural Gas, (6)	NATURAL GAS	108 MW	GCP	0.0086 LB/MMBTU	BACT-PSD
Rincon Power Plant	GA	3/24/2003	Combustion Turbine, (2)	NATURAL GAS	171.7 MW	Oxidation Catalyst	2 PPM @ 15% O2	BACT-PSD
Other States								
Calcasieu Plant	LA	12/21/2011	Turbine Exhaust Stack No. 1 & No. 2	NATURAL GAS	1900 MM BTU/H EACH	DLN Combustors	7 LB/H	BACT-PSD
Pseg Fossil Llc Keamy Generating Station	NJ	10/27/2010	Simple Cycle Turbine	Natural Gas	8940000 MMBtu/year (HHV;	Oxidation Catalyst and CGP	4 PPMVD@15% O2	OTHER CASE-BY-CASE
Bosque County Power Plant	TX	2/27/2009	Electrical Generation	NATURAL GAS	170 MW	BACT IS THE USE OF GCP TO MINIMIZE THE F	4 PPMVD	BACT-PSD
CPV St Charles	MD	11/12/2008	Combustion Turbines (2)	NATURAL GAS		OXIDATION CATALYST	1 PPMVD @ 15% O2	LAER
NRG Texas Electric Power Generation	TX	4/19/2006	Annual Limits	NATURAL GAS AND FUEL OIL			38.8 T/YR	BACT-PSD
Dayton Power And Light Company	OH	3/7/2006	Combustion Turbines (2), Simple Cycle	NATURAL GAS	1115 MMBTU/H		10 LB/H	OTHER CASE-BY-CASE
Rolling Hills Generating Plant	OH	1/17/2006	Natural Gas Fired Turbines (5)	NATURAL GAS	209 MW		3.2 LB/H	BAT (Non-US ONLY)
Rohm And Haas Chemicals Llc Lone Star Plant	TX	3/24/2005	L-Area Gas Turbine	NATURAL GAS			0.59 LB/H	RACT
Jack County Power Plant	TX	7/22/2003	Combustion Turbine With 550 Mmbtu/Hr Duct Burner	NATURAL GAS		GCP	20.6 LB/H	BACT-PSD
Exxon Mobil Chemical Baytown Olefins Plant	TX	6/13/2003	164 Mw Gas Turbine-Case 1	NATURAL GAS			3.17 LB/H	BACT-PSD
Union Carbide Texas City Operations	TX	1/23/2003	Turbine Only	NATURAL GAS	12000 LB/H		0.16 LB/H	BACT-PSD
Chickahominy Power	VA	1/10/2003	Turbine, Simple Cycle, Natural Gas, (4)	NATURAL GAS	182.6 MW	CLEAN FUEL, GCP	3.7 LB/H	BACT-PSD

Source: EPA 2013 (RBLC database); Golder, 2013

Note: DLN= dry low NOx; GCP= good combustion practices.

Table D-6: Summary of VOC BACT Determinations for ULSD Fuel Oil-Fired CTs (2003-2013)

Facility Name	State	Permit Issued	Process Info	Heat Input	Fuel	Control Method	VOC Limit	Basis
Florida								
FPL Martin Plant	FL	4/16/2003	Turbine, Simple Cycle, Fuel Oil (4)	170 MW	NO.2 FUEL OIL	GCP	2.5 PPMVD @ 15% O2	BACT-PSD
EPA Region 4 (AL, FL, GA, KY, MS, NC, SC, TN)								
Talbot Energy Facility	GA	6/9/2003	Turbine, Simple Cycle, Fuel Oil, (2)	108 MW	NO.2 FUEL OIL		0.0149 LB/MMBTU	BACT-PSD
TVA - Kemper Combustion Turbine Plant	MS	12/10/2004	GE Combustion Turbine (4)	1278 MMBTU/H	NO.2 FUEL OIL		70 LB/R	BACT-PSD
Other States								
Dayton Power & Light Energy Llc	OH	12/3/2009	Turbines (4), Simple Cycle, Fuel Oil #2	4216 H/YR	NO.2 FUEL OIL		5.5 LB/H	BACT-PSD
CPV St Charles	MD	11/12/2008	Internal Combustion Engine - Emergency Generator		NO.2 FUEL OIL		4.8 G/HP-H	BACT-PSD
Arsenal Hill Power Plant	LA	3/20/2008	Dfp Diesel Fire Pump	310 HORSEPOWER	NO.2 FUEL OIL	Use Of Low-Sulfur Fuels, Limiting Operating Hours And Proper Engine Maintenance	0.77 LB/H	BACT-PSD
Creole Trail Lng Import Terminal	LA	8/15/2007	Submerged Combustion Vaporizer Nos. 1-21	108 MMBTU/H EA.	NO.2 FUEL OIL	GCP	0.32 LB/H	BACT-PSD
Dayton Power And Light Company	OH	3/7/2006	Combustion Turbines (2), Simple Cycle	1115 MMBTU/H	NO.2 FUEL OIL		10 LB/H	OTHER CASE-BY-CASE
Dayton Power And Light Company	OH	3/7/2006	Combustion Turbine (1), Simple Cycle	1115 MMBTU/H	NO.2 FUEL OIL		10 LB/H	OTHER CASE-BY-CASE
Chickahominy Power	VA	1/10/2003	Turbine, Simple Cycle, Fuel Oil, (4)	182.6 MW	NO.2 FUEL OIL	Clean fuel, GCP	27.6 LB/H	BACT-PSD

Source: EPA 2013 (RBLC database); Golder, 2013

Note: DLN= dry low NOx; GCP= good combustion practices.

Table D-7: Summary of GHG (CO2e) BACT Determinations for Natural Gas-Fired CTs (2003-2013)

Facility Name	State	Permit Issued	Process Info	Heat Input	Control Method	CO_2e Limit	Basis
PIO PICO ENERGY CENTER	CA	4/29/2013	COMBUSTION TURBINES (NORMAL OPERATION)	300 MW		1,328 LB/MW-HR	BACT-PSD
R.M. HESKETT STATION	ND	5/8/2013	Combustion Turbine	986 MMBtu/hr		413,198 TONS	BACT-PSD
SABINE PASS LNG TERMINAL	LA	5/11/2012	Simple Cycle Generation Turbines (2)	286 MMBTU/H	GCP and fueled by natural gas - use GE LM2500+G4 turbines	4,872,107 TONS/YR	BACT-PSD

Source: EPA 2013 (RBLC database); Golder, 2013

Note: GCP= good combustion practices

Table D-8: Summary of PM BACT Determinations for Natural Gas-Fired CTs (2003-2013)

Facility Name	State	Permit Issued	Process Info	Heat Input	pollutant	Control Method	$PM/PM_{10}/PM_{2.5}$ Limit	$PM/PM_{10}/PM_{2.5}$ Emissions Rate	Basis
Florida									
Shady Hills Generating Station	FL	1/12/2009	Two Simple Cycle Combustion Turbine - Model 7fa	170 MW	PM10		10 % OPACITY		BACT-PSD
Jacksonville Electric Authority/Jea	FL	12/22/2006	Simple Cycle Turbine 172 Mw	1804 MMBTU/H	filterable PM10	Clean Fuel			BACT-PSD
Oleander Power Project	FL	11/17/2006	Simple Cycle Combustion Turbine	190 MW	filterable PM10	Clean Fuel	1.5 GR S/100 SCF		BACT-PSD
TEC/Polk Power Energy Station	FL	4/28/2006	Simple Cycle Gas Turbine	1834 MMBTU/H	filterable PM10	Clean Fuel, GCP	10 % OPACITY		BACT-PSD
FPL Martin Plant	FL	4/16/2003	Turbine, Simple Cycle, Natural Gas, (4)	170 MW	filterable PM10	Clean Fuel			BACT-PSD
FPL Manatee Plant - Unit 3	FL	4/15/2003	Turbine, Simple Cycle, Natural Gas, (4)	170 MW	filterable PM10	Clean Fuel			BACT-PSD
EPA Region 4 (AL, FL, GA, KY, MS, NC, SC, TN)									
Dahlberg Combusdtion Turbine Electric Generating Facility	GA	5/14/2010	Simple Cycle Combustion Turbine	1530 MW	PM10	Clean Fuel, GCP		0.011 LB/MMBTU	BACT-PSD
TVA - Kemper Combustion Turbine Plant	MS	12/10/2004	GE Combustion Turbine (4)	1278 MMBTU/H	PM			0.0084 LB/MMBTU	OTHER CASE-BY-CASE
Moselle Plant	MS	12/10/2004	Combustion Turbine, Gas-Fired, Simple-Cycle	1143.3 MMBTU/H	filterable PM10			10 LB/H	BACT-PSD
Talbot Energy Facility	GA	6/9/2003	Turbine, Simple Cycle, Natural Gas, (6)	108 MW	PM	Clean Fuel		7.35 LB/H	BACT-PSD
Louisville Gas And Electric Company	KY	6/6/2003	Turbine, Simple Cycle, Natural Gas (6)	160 MW	PM	GCP		7.35 LB/H	BACT-PSD
SMEPA - Silver Creek Generating	MS	5/29/2003	Turbine, Simple Cycle (3)	1109.3 MMBTU/H	filterable PM10	Clean Fuel, GCP		7.35 LB/H	BACT-PSD
Rincon Power Plant	GA	3/24/2003	Combustion Turbine, (2)	171.7 MW	PM	Clean Fuel		7.35 LB/H	BACT-PSD
Warren Peaking Power Facility (Warren Power, L	MS	1/30/2003	Turbines, Simple Cycle, Natural Gas (4)	959.8 MMBTU/H	PM	Clean Fuel		7 LB/H	BACT-PSD
Warren Peaking Power Facility (Warren Power, L	MS	1/30/2003	Turbines, Simple Cycle, Natural Gas (4)	959.8 MMBTU/H	filterable PM10	Clean Fuel		7 LB/H	BACT-PSD
Other States									
R.M. Heskett Station	ND	2/22/2013	Combustion Turbine	986 MMBtu/hr	PM10	GCP		7.3 LB/HR	BACT-PSD
Pio Pico Energy Center	CA	11/19/2012	Combustion Turbines (Normal Operation)	300 MW	PM10	Clean Fuel		0.0065 LB/MMBTU (HI	BACT-PSD
Great River Energy - Elk River Station	MN	7/1/2008	Combustion Turbine Generator	2169 MMBTU/H	PM10	Clean Fuel			BACT-PSD
Great River Energy - Elk River Station	MN	7/1/2008	Combustion Turbine Generator	2169 MMBTU/H	filterable PM10	Clean Fuel			BACT-PSD
Great River Energy - Elk River Station	MN	7/1/2008	Combustion Turbine Generator	2169 MMBTU/H	filterable PM10	Clean Fuel			BACT-PSD
Western Farmers Electric Anadarko	OK	6/13/2008	Combustion Turbine Peaking Unit(S)	462.7 MMBTU/H	filterable PM10			4 LB/H	BACT-PSD
Rawhide Energy Station	CO	8/31/2007	Unit F Combustion Turbine	1400 MMBTU/H	PM	Clean Fuel		18 LB/H	BACT-PSD
Rawhide Energy Station	CO	8/31/2007	Unit F Combustion Turbine	1400 MMBTU/H	filterable PM10	Clean Fuel		18 LB/H	BACT-PSD
Dayton Power And Light Company	OH	3/7/2006	Combustion Turbine (1), Simple Cycle	1115 MMBTU/H	filterable PM10			8 LB/H	OTHER CASE-BY-CASE
Dayton Power And Light Company	OH	3/7/2006	Combustion Turbines (2), Simple Cycle	1115 MMBTU/H	filterable PM10			8 LB/H	OTHER CASE-BY-CASE
We Energies Concord	WI	1/26/2006	Combustion Turbine, 100 Mw, Natural Gas	100 MW	PM			39 LB/H	BACT-PSD
Rolling Hills Generating Plant	OH	1/17/2006	Natural Gas Fired Turbines (5)	209 MW	PM			17.3 LB/H	BAT (Non-US ONLY)
Rolling Hills Generating Plant	OH	1/17/2006	Natural Gas Fired Turbines (5)	209 MW	filterable PM10			17.3 LB/H	BACT-PSD
South Harper Peaking Facility	MO	12/29/2004	Turbines, Simple Cycle, Natural Gas, (3)	1455 MMBTU/H	filterable PM10	GCP		15.25 LB/H	
Fairbault Energy Park	MN	7/15/2004	Turbine, Simple Cycle, Natural Gas (1)	1663 MMBTU/H	filterable PM10	Clean Fuel, GCP		0.01 LB/MMBTU	BACT-PSD
Fredonia Energy Station	WA	7/18/2003	Turbines, Simple Cycle, (2)	108 MW	filterable PM10	Clean Fuel, GCP	0.01 GR/DSCF		BACT-PSD
Exxon Mobil Chemical Baytown Olefins Plant	TX	6/13/2003	Gas Turbine-Case 1	164 MW	PM			18 LB/H	BACT-PSD
ODEC - Louisa Facility	VA	3/11/2003	Turbine, Simple Cycle, (1), Natural Gas	1624 MMBTU/H	filterable PM10	GCP		18 LB/H	N/A
ODEC - Louisa	VA	3/11/2003	Turbine, Simple Cycle, Natural Gas (1)	1624 MMBTU/H	filterable PM10	Clean Fuel, GCP		18 LB/H	BACT-PSD
ODEC -Marsh	VA	2/14/2003	Turbine, Simple Cycle, Natural Gas, (4)	1624 MMBTU/H	filterable PM10	Clean Fuel, GCP		18 LB/H	BACT-PSD
Chickahominy Power	VA	1/10/2003	Turbine, Simple Cycle, Natural Gas, (4)	182.6 MW	filterable PM10	Clean Fuel, GCP		27 LB/H	BACT-PSD

Table D-9: Summary of PM BACT Determinations for ULSD Oil-Fired CTs (2000-2013)

Facility Name	State	Permit Issued	Process Info	Heat Input	Fuel	Pollutant	Control Method	$PM/PM_{10}/PM_{2.5}$ Limit	$PM/PM_{10}/PM_{2.5}$ Emissions Rate	Basis
Florida										
FPL Martin Plant	FL	4/16/2003	Turbine, Simple Cycle, Fuel Oil (4)	170 MW	NO.2 FUEL OIL	filterable PM10	Clean Fuel			BACT-PSD
Greenland Energy Center	FL	3/10/2009	Combustion Turbine	190 MW	NO.2 FUEL OIL	PM10	Clean Fuel	10% OPACITY		BACT-PSD
EPA Region 4 (AL, FL, GA, KY, MS, NC, SC, TN)										
Talbot Energy Facility	GA	6/9/2003	Turbine, Simple Cycle, Fuel Oil, (2)	108 MW	NO.2 FUEL OIL	PM	Clean Fuel		0.023 LB/MMBTU	BACT-PSD
TVA - Kemper Combustion Turbine Plant	MS	12/10/2004	GE Combustion Turbine (4)	1278 MMBTU/H	NO.2 FUEL OIL	filterable PM10	Clean Fuel		15.8 LB/H	BACT-PSD
Broad River Energy Center	SC	5/22/2003	Combustion Turbines		NO.2 FUEL OIL	PM	Clean Fuel		46 LB/H	BACT-PSD
Other States										
Dayton Power And Light Company	OH	3/7/2006	Combustion Turbines (2), Simple Cycle	1115 MMBTU/H	NO.2 FUEL OIL	filterable PM10	Clean Fuel		15 LB/H	OTHER CASE-BY-CASE
Dayton Power And Light Company	OH	3/7/2006	Combustion Turbine (1), Simple Cycle	1115 MMBTU/H	NO.2 FUEL OIL	filterable PM10	Clean Fuel		15 LB/H	OTHER CASE-BY-CASE
Fairbault Energy Park	MN	7/15/2004	Turbine, Simple Cycle, Distillate Oil (1)	1576 MMBTU/H	NO.2 FUEL OIL	PM	Clean Fuel		0.03 LB/MMBTU	BACT-PSD
ODEC - Louisa Facility	VA	3/11/2003	Turbine, Simple Cycle, (1), Fuel Oil	1820 MMBTU/H	NO.2 FUEL OIL	filterable PM10	Clean Fuel		36 LB/H	N/A
ODEC - Louisa	VA	3/11/2003	Turbine, Simple Cycle, Fuel Oil (1)	1820 MMBTU/H	NO.2 FUEL OIL	filterable PM10	Clean Fuel		36 LB/H	BACT-PSD
ODEC - Marsh Run Facility	VA	2/14/2003	Turbine, Simple Cycle, (4), Fuel Oil	1803 MMBTU/H	NO.2 FUEL OIL	filterable PM10	Clean Fuel		36 LB/H	N/A
Chickahominy Power	VA	1/10/2003	Turbine, Simple Cycle, Fuel Oil, (4)	182.6 MW	NO.2 FUEL OIL	filterable PM10	Clean Fuel		27 LB/H	BACT-PSD

Source: EPA 2013 (RBLC database); Golder, 2013

Note: GCP= good combustion practices

APPENDIX E

FDEP FORM NO. 62-210.900(1)
APPLICATION FOR AIR PERMIT – LONG FORM

Department of Environmental Protection

Division of Air Resource Management

RECEIVED
JUL 31 2013
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 Power & Light Company**	
2. Site Name: **Fort Myers Plant**	
3. Facility Identification Number: **0710002**	
4. Facility Location... Street Address or Other Locator: **Fort Myers Power Plant 10650 State Road 80** City: **Fort Myers** County: **Lee** Zip Code: **33905**	
5. Relocatable Facility? ☐ Yes ☒ No	6. Existing Title V Permitted Facility? ☒ Yes ☐ No

Application Contact

1. Facility Contact Name: **Matthew Raffenberg, Director of Environmental Licensing**
2. Facility Contact Mailing Address... Organization/Firm: **Florida Power & Light Company** Street Address: **700 Universe Boulevard, JES/JB** City: **Juno Beach** State: **FL** Zip Code: **33408**
3. Facility Contact Telephone Numbers: Telephone: **(561) 691-7518** ext. Fax: **(561) 691-7070**
4. Facility Contact E-mail Address: **Matthew.Raffenberg@FPL.com**

Application Processing Information (DEP Use)

1. Date of Receipt of Application: 7-31-13	3. PSD Number (if applicable):
2. Project Number(s): 0710002-019-AC	4. Siting Number (if applicable):

PSD-FL-422

APPLICATION INFORMATION

Purpose of Application

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

Air Construction Permit

☒ Air construction permit.

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

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

Air Operation Permit

☐ Initial Title V air operation permit.

☐ Title V air operation permit revision.

☐ Title V air operation permit renewal.

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

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

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

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

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

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

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

Application Comment

This application is for the Site Certification Application (SCA) modification and environmental permitting associated with the replacement of gas turbines (GTs) at the FPL Fort Myers Plant, Lee County, Florida. FPL plans to replace the existing 12 simple cycle GTs with a net capability of 600 megawatts (MW) with three simple cycle combustion turbines (CTs) that will be rated at approximately 200 MW each (Fort Myers CT Project). The three new CTs will be designated Units 3C through 3E.

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Processing Fee
Unit 3C through 3E	Three Siemens Simple-Cycle Combustion Turbines	AC1A	
	-OR-		
Unit 3C through 3E	Three GE Simple-Cycle Combustion Turbines	AC1A	
	-AND-		
2	Four Black-Start Diesel Engines	AC1A	

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 : **Randall R. LaBauve, Vice President, Environmental Services**
2.	Owner/Authorized Representative Mailing Address... Organization/Firm: **Florida Power & Light Company** Street Address: **700 Universe Boulevard, JES/JB** City: **Juno Beach** State: **FL** Zip Code: **33408**
3.	Owner/Authorized Representative Telephone Numbers... Telephone: **(561) 691-7001** ext. Fax: **(561) 691-7070**
4.	Owner/Authorized Representative E-mail Address: **Randall.R.LaBauve@FPL.com**
5.	Owner/Authorized Representative Statement: *I, the undersigned, am the owner or authorized representative of the corporation, partnership, or other legal entity submitting this air permit application. To the best of my knowledge, the statements made in this application are true, accurate and complete, and any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department.* [signature] Signature 7/29/2013 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 or CAIR source.

3. Application Responsible Official Mailing Address...
   Organization/Firm:
   Street Address:
   City: State: Zip Code:

4. Application Responsible Official Telephone Numbers...
   Telephone: ( ) ext. Fax: ( )

5. Application Responsible Official E-mail Address:

6. Application Responsible Official Certification:

I, the undersigned, am a responsible official of the Title V source addressed in this air permit application. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof and all other applicable requirements identified in this application to which the Title V source is subject. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department, and I will promptly notify the department upon sale or legal transfer of the facility or any permitted emissions unit. Finally, I certify that the facility and each emissions unit are in compliance with all applicable requirements to which they are subject, except as identified in compliance plan(s) submitted with this application.

______________________ ______________
Signature Date

APPLICATION INFORMATION

Professional Engineer Certification

1.	Professional Engineer Name: **Kennard F. Kosky** Registration Number: **14996**
2.	Professional Engineer Mailing Address... Organization/Firm: **Golder Associates Inc.**** Street Address: **6026 NW 1st Place** City: **Gainesville** State: **FL** Zip Code: **32607**
3.	Professional Engineer Telephone Numbers... Telephone: **(352) 336-5600** ext. **21156** Fax: **(352) 336-6603**
4.	Professional Engineer E-mail Address: **Ken_Kosky@golder.com**
5.	Professional Engineer Statement: *I, the undersigned, hereby certify, except as particularly noted herein*, that:* *(1) To the best of my knowledge, there is reasonable assurance that the air pollutant emissions unit(s) and the air pollution control equipment described in this application for air permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; and* *(2) To the best of my knowledge, any emission estimates reported or relied on in this application are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of hazardous air pollutants not regulated for an emissions unit addressed in this application, based solely upon the materials, information and calculations submitted with this application.* *(3) If the purpose of this application is to obtain a Title V air operation permit (check here ☐, if so), I further certify that each emissions unit described in this application for air permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance plan and schedule is submitted with this application.* *(4) If the purpose of this application is to obtain an air construction permit (check here ☒, if so) or concurrently process and obtain an air construction permit and a Title V air operation permit revision or renewal for one or more proposed new or modified emissions units (check here ☐, if so), I further certify that the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.* *(5) If the purpose of this application is to obtain an initial air operation permit or operation permit revision or renewal for one or more newly constructed or modified emissions units (check here ☐, if so), I further certify that, with the exception of any changes detailed as part of this application, each such emissions unit has been constructed or modified in substantial accordance with the information given in the corresponding application for air construction permit and with all provisions contained in such permit.* Signature [signature] Date 7/24/13 (seal) No. 14996 STATE OF FLORIDA PROFESSIONAL ENGINEER

* Attach any exception to certification statement.

**Board of Professional Engineers Certificate of Authorization #00001670.

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates... Zone **17** East (km) **422.3** North (km) **2952.9**		2. Facility Latitude/Longitude... Latitude (DD/MM/SS) **26/41/49** Longitude (DD/MM/SS) **81/46/55**	
3. Governmental Facility Code: **0**	4. Facility Status Code: **A**	5. Facility Major Group SIC Code: **49**	6. Facility SIC(s): **4911**
7. Facility Comment :			

Facility Contact

1. Facility Contact Name: **Karl Kauffman, Plant General Manager**
2. Facility Contact Mailing Address... Organization/Firm: **Fort Myers Power Plant** Street Address: **10560 State Road 80** City: **Fort Myers** State: **FL** Zip Code: 33905
3. Facility Contact Telephone Numbers: Telephone: **(239) 693-4252** ext. Fax: **(239) 693-4333**
4. Facility Contact E-mail Address:

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 E-mail Address:

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:

FPL Combustion Turbines are subject to NSPS 40 CFR 60 Subpart KKKK and 40 CFR 63 Subpart YYYY.

The facility has several reciprocating internal combustion engines (RICE) that are subject to 40 CFR 60 Subpart IIII 40 CFR 63 Subpart ZZZZ.

List of Pollutants Emitted by Facility

1. Pollutant Emitted	2. Pollutant Classification	3. Emissions Cap [Y or N]?
PM/PM10	**A**	**N**
NOx	**A**	**N**
CO	**A**	**N**
VOC	**A**	**N**
SO2	**A**	**N**
Pb	**A**	**N**
SAM	**A**	**N**
HAPS	**A**	**N**

B. EMISSIONS CAPS

Facility-Wide or Multi-Unit Emissions Caps

1. Pollutant Subject to Emissions Cap	2. Facility-Wide Cap [Y or N]? (all units)	3. Emissions Unit ID's Under Cap (if not all units)	4. Hourly Cap (lb/hr)	5. Annual Cap (ton/yr)	6. Basis for Emissions Cap

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

C. FACILITY ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Facility Plot Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **See Air Report** ☐ 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: **See Air Report** ☐ 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: **See Air Report** ☐ Previously Submitted, Date:__________

Additional Requirements for Air Construction Permit Applications

1. Area Map Showing Facility Location: ☒ Attached, Document ID: **See Air Report** ☐ Not Applicable (existing permitted facility)
2. Description of Proposed Construction, Modification, or Plantwide Applicability Limit (PAL): ☒ Attached, Document ID: **See Air Report**
3. Rule Applicability Analysis: ☒ Attached, Document ID: **See Air Report**
4. List of Exempt Emissions Units: ☐ 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: **See Air Report** ☐ Not Applicable
7. Source Impact Analysis (Rule 62-212.400(5), F.A.C.): ☒ Attached, Document ID: **See Air Report** ☐ Not Applicable
8. Air Quality Impact since 1977 (Rule 62-212.400(4)(e), F.A.C.): ☒ Attached, Document ID: **See Air Report** ☐ Not Applicable
9. Additional Impact Analyses (Rules 62-212.400(8) and 62-212.500(4)(e), F.A.C.): ☒ Attached, Document ID: **See Air Report** ☐ Not Applicable
10. Alternative Analysis Requirement (Rule 62-212.500(4)(g), F.A.C.): ☐ Attached, Document ID:__________ ☒ Not Applicable

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

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: FPL-AR-1 ☐ 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: FPL-AR-3 ☐ Previously Submitted, Date:__________ ☐ Not Applicable (not a CAIR source)

Additional Requirements Comment

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.

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:
   Three GE Simple-Cycle CTs or Siemens Simple-Cycle CTs.

3. Emissions Unit Identification Number: **Units 3C, 3D, and 3E**

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:
A	**2014**	**2016**	**49**

8. Federal Program Applicability: (Check all that apply)

   ☒ Acid Rain Unit

   ☒ CAIR Unit

9. Package Unit:
   Manufacturer: Model Number:

10. Generator Nameplate Rating: **200** MW/CT

11. Emissions Unit Comment:

Emissions Unit Control Equipment/Method: Control 1 of 2

1. Control Equipment/Method Description:
Natural Gas: Low NOx combustion technology

2. Control Device or Method Code: **205**

Emissions Unit Control Equipment/Method: Control 2 of 2

1. Control Equipment/Method Description:
Distillate Fuel Oil:
Water Injection
Ultra-low Sulfur Fuel

2. Control Device or Method Code: **028, 148**

Emissions Unit Control Equipment/Method: Control ____ of ____

1. Control Equipment/Method Description:

2. Control Device or Method Code:

Emissions Unit Control Equipment/Method: Control ____ of ____

1. Control Equipment/Method Description:

2. Control Device or Method Code:

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:	million Btu/hr	
4.	Maximum Incineration Rate:	pounds/hr tons/day	
5.	Requested Maximum Operating Schedule:	**24** hours/day **52** weeks/year	**7** days/week **3,390** hours/year
6.	Operating Capacity/Schedule Comment: **See Tables S-A-1 and GE-A-1 for maximum heat input when firing natural gas; and Tables S-A-2 and GE-A-2 for maximum heat input when firing ultra low sulfur oil.**		

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:	2. Emission Point Type Code: **1**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: **The combustion gases exhaust through a 100.5-ft stack.**	
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:	

5. Discharge Type Code: **V**	6. Stack Height: **100.5** feet	7. Exit Diameter: **23** feet
8. Exit Temperature: **See Air Report**°F	9. Actual Volumetric Flow Rate: **See Air Report** acfm	10. Water Vapor: %

11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates... Zone: East (km): North (km):	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment: **See Tables GE-A-1 and S-A-1 for the stack paramenters associated with each CT when firing natural gas and ultra low sulfur fuel oil.**	

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type): **Internal Combustion Engines; Electric Generation; Distillate Oil (Diesel);Turbine**		
2. Source Classification Code (SCC): **2-01-001-01**	3. SCC Units: **1,000 Gallons burned**	
4. Maximum Hourly Rate: **81.6**	5. Maximum Annual Rate: **40,816**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.0015**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **131**
10. Segment Comment: **Million British thermal units (Btu) per SCC unit =131. Based on 7.1 lb/gal; LHV = 18,300 Btu/lb ISO conditions. Max hourly rate based on 35 F and 500 hours per year operation. Based on GE Units per CT. Data shown for Siemens F5. See Table GE-A-1 and S-A-1 in Air Permit Application Report.**		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type): **Internal Combustion Engines; Electric Generation; Natural Gas;Turbine**		
2. Source Classification Code (SCC): **2-01-002-01**	3. SCC Units: **Million Cubic Feet Burned**	
4. Maximum Hourly Rate: **11.3**	5. Maximum Annual Rate: **98,669**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **918**
10. Segment Comment: **Based on 918 Btu/cf (LHV). Max hourly rate based on 75 F. Max annual rate based on 75 F and 8,760 hr/yr operation. Information shown for Siemens F5 CT. See Tables GE-A-1 and S-A-1 in Air Report.t**		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
NOx	205, 028		EL
CO			EL
SO2	148		EL
VOC			EL
PM			EL
PM10			EL
SAM	148		EL

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **NOx**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **See Air Report** lb/hour **See Air Report** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **See Air Report** Reference:	7. Emissions Method Code:
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **See Air Report, Appendix C in Air Report for baseline actual emissions. Tables S-A-1 and S-A-2 for Siemens; Tables GE-A-1 and GE-A-2 for GE.**	
11. Potential, Fugitive, and Actual 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 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **See Air Report; Table 4-1**	4. Equivalent Allowable Emissions: **See Air Report** lb/hour **See Air Report** tons/year
5. Method of Compliance: **See Air Report, Table 4-1**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions ____ of ____

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

Allowable Emissions Allowable Emissions ____ of ____

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

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **Carbon Monoxide- CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **See Air Report** lb/hour **See Air Report** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **See Air Report** Reference:	7. Emissions Method Code:
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **See Air Report, Appendix C for baseline actual emissions. Tables S-A-1 and S-A-2 for Siemens; Tables GE-A-1 and GE-A-2 for GE.**	
11. Potential, Fugitive, and Actual 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 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **See Air Report; Table 4-1**	4. Equivalent Allowable Emissions: **See Air Report** lb/hour **See Air Report** tons/year
5. Method of Compliance: **See Air Report, Table 4-1**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions ____ of ____

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

Allowable Emissions Allowable Emissions ____ of ____

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

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS
(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **Sulfur Dioxide - SO2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **See Air Report** lb/hour **See Air Report** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **See Air Report** Reference:	7. Emissions Method Code:
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **See Air Report, Appendix C for baseline actual emissions. Tables S-A-1 and S-A-2 for Siemens; Tables GE-A-1 and GE-A-2 for GE.**	
11. Potential, Fugitive, and Actual 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 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **See Air Report; Table 4-1**	4. Equivalent Allowable Emissions: **See Air Report** lb/hour **See Air Report** tons/year
5. Method of Compliance: **See Air Report, Table 4-1**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions ____ of ____

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

Allowable Emissions Allowable Emissions ____ of ____

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

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **Volatile Organic Compounds - VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **See Air Report** lb/hour **See Air Report** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **See Air Report** Reference:	7. Emissions Method Code:
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **See Air Report, Appendix C for baseline actual emissions. Tables S-A-1 and S-A-2 for Siemens; Tables GE-A-1 and GE-A-2 for GE.**	
11. Potential, Fugitive, and Actual 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 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **See Air Report; Table 4-1**	4. Equivalent Allowable Emissions: **See Air Report** lb/hour **See Air Report** tons/year
5. Method of Compliance: **See Air Report, Table 4-1**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions ____ of ____

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

Allowable Emissions Allowable Emissions ____ of ____

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

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **Particulate Matter - PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **See Air Report** lb/hour **See Air Report** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **See Air Report** Reference:	7. Emissions Method Code:
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **See Air Report, Appendix C for baseline actual emissions. Tables S-A-1 and S-A-2 for Siemens; Tables GE-A-1 and GE-A-2 for GE.**	
11. Potential, Fugitive, and Actual 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 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **See Air Report; Table 4-1**	4. Equivalent Allowable Emissions: **See Air Report** lb/hour **See Air Report** tons/year
5. Method of Compliance: **See Air Report, Table 4-1**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions ____ of ____

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

Allowable Emissions Allowable Emissions ____ of ____

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

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **PM10**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **See Air Report** lb/hour **See Air Report** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **See Air Report** Reference:	7. Emissions Method Code:
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **See Air Report, Appendix C for baseline actual emissions. Tables S-A-1 and S-A-2 for Siemens; Tables GE-A-1 and GE-A-2 for GE.**	
11. Potential, Fugitive, and Actual 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 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **See Air Report; Table 4-1**	4. Equivalent Allowable Emissions: **See Air Report** lb/hour **See Air Report** tons/year
5. Method of Compliance: **See Air Report, Table 4-1**	
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):	

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 1 of 2

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: **100** % Maximum Period of Excess Opacity Allowed: **60** min/hour	
4. Method of Compliance: **EPA Method 9**	
5. Visible Emissions Comment: **FDEP Rule 62-296.320(4)(b)1, F.A.C., requires 20 percent opacity. Excess emissions provided by Rule 62-210.700(1).**	

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

1. Visible Emissions Subtype: **VE10**	2. Basis for Allowable Opacity: ☐ Rule ☒ Other
3. Allowable Opacity: Normal Conditions: **10** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **EPA Method 9**	
5. Visible Emissions Comment: **Proposed as emission limit for PM/PM_{10}.**	

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: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **CEM required pursuant to 40 CFR 75. NO_X monitoring includes diluent monitor (O_2 or CO_2). CO_2 CEM may be used to comply with GHG permit limit.**	

Continuous Monitoring System: Continuous Monitor 2 of 2

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

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

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

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

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: **See Air Reports** ☐ Not Applicable
2.	Good Engineering Practice Stack Height Analysis (Rules 62-212.400(4)(d) and 62-212.500(4)(f), F.A.C.): ☒ Attached, Document ID: **See Air Reports** ☐ Not Applicable
3.	Description of Stack Sampling Facilities: (Required for proposed new stack sampling facilities only) ☒ Attached, Document ID: **See Air Reports** ☐ 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

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.

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:
   Four Black-Start Engines.

3. Emissions Unit Identification Number:

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:
A	**2014**	**2016**	**49**

8. Federal Program Applicability: (Check all that apply)

   ☐ Acid Rain Unit

   ☐ CAIR Unit

9. Package Unit:
   Manufacturer: Model Number:

10. Generator Nameplate Rating: MW/CT

11. Emissions Unit Comment:

Emissions Unit Control Equipment/Method: Control ____ of ____

1. Control Equipment/Method Description:
2. Control Device or Method Code:

Emissions Unit Control Equipment/Method: Control ____ of ____

1. Control Equipment/Method Description:
2. Control Device or Method Code:

Emissions Unit Control Equipment/Method: Control ____ of ____

1. Control Equipment/Method Description:
2. Control Device or Method Code:

Emissions Unit Control Equipment/Method: Control ____ of ____

1. Control Equipment/Method Description:
2. Control Device or Method Code:

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: **116** million Btu/hr
4.	Maximum Incineration Rate: pounds/hr tons/day
5.	Requested Maximum Operating Schedule: hours/day days/week weeks/year **100** hours/year
6.	Operating Capacity/Schedule Comment: **29 MMBtu/hr for each engines**

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:		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: **30** feet	7. Exit Diameter: **2** feet
8. Exit Temperature: **893**°F	9. Actual Volumetric Flow Rate: **24,283** acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: dscfm		12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates... Zone: East (km): North (km):		14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment: **Stack parameters for one black start generator.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 1

1. Segment Description (Process/Fuel Type): **Internal Combustion Engines; Electric Generation; Distillate Oil (Diesel);Turbine**		
2. Source Classification Code (SCC): **2-01-001-01**	3. SCC Units: **1,000 Gallons burned**	
4. Maximum Hourly Rate: **0.211**	5. Maximum Annual Rate: **21.1**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.0015**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **137.7**
10. Segment Comment: **Max hourly rate=29.01 MMBtu/hr / (137.7 MMBtu/kgal)=0.211 kgal/hr** **Max annual rate=0.211 kgal/hr x 100 hr/yr=21.1 kgal/yr**		

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:		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
NOx			EL
CO			EL
SO2	Fuel Quality		EL
VOC			EL
PM			EL
PM10			EL

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **NOx**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **47.6** lb/hour **2.4** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **5.2 g/hr-hr** Reference: **Manufacturer information**	7. Emissions Method Code: **2**
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:
5.2 g/hp-hr x 4,157 hp x 1 lb/453.6 g = 47.6 lb/hr
47.6 lb/hr x 100 hr x 1 ton/2,000 lb = 2.4 TPY

11. Potential, Fugitive, and Actual Emissions Comment:
Emissions are for one generator.

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: **Subpart IIII NSPS**	4. Equivalent Allowable Emissions: **47.6** lb/hour **2.4** tons/year
5. Method of Compliance: **Manufacturer certification of applicable Subpart IIII standards.**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions ____ of ____

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

Allowable Emissions Allowable Emissions ____ of ____

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

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **6.0** lb/hour **0.3** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.7 g/hr-hr** Reference: **Manufacturer informaton**	7. Emissions Method Code: **2**
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: **0.7 g/hp-hr x 4,157 hp x 1 lb/453.6 g = 6.0 lb/hr** **6.0 lb/hr x 100 hr x 1 ton/2,000 lb = 0.3 TPY**	
11. Potential, Fugitive, and Actual Emissions Comment: **Emissions are for one generator.**	

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: **Subpart IIIi NSPS**	4. Equivalent Allowable Emissions: **6.0** lb/hour **0.3** tons/year
5. Method of Compliance: **Manufacturer certification of applicable Subpart IIII standards.**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions ____ of ____

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

Allowable Emissions Allowable Emissions ____ of ____

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

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **Sulfur Dioxide - SO2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.045** lb/hour **0.0022** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.0015% S fuel oil** Reference: **FPL, 2013**	7. Emissions Method Code: **2**
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: **0.0015% S x 64/32 x 7.1 lb/gal x 210.7 gal/hr = 0.045 lb/hr** **0.045 lb/hr x 100 hr x 1 ton/2,000 lb = 0.0022 TPY**	
11. Potential, Fugitive, and Actual Emissions Comment: **Emissions are for one generator.**	

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: **0.0015% S fuel oil**	4. Equivalent Allowable Emissions: **0.045** lb/hour **0.0022** tons/year
5. Method of Compliance: **Fuel vendor information**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions ____ of ____

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

Allowable Emissions Allowable Emissions ____ of ____

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

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.9** lb/hour **0.05** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.1 g/hr-hr** Reference: **Manufacturer information**	7. Emissions Method Code: **2**
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: **0.1g/hp-hr x 4,157 hp x 1 lb/453.6 g = 0.9 lb/hr** **0.9 lb/hr x 100 hr x 1 ton/2,000 lb = 0.05 TPY**	
11. Potential, Fugitive, and Actual Emissions Comment: **Emissions are for one generator.**	

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: **Subpart IIII NSPS**	4. Equivalent Allowable Emissions: **0.9** lb/hour **0.05** tons/year
5. Method of Compliance: **Manufacturer certification of applicable Subpart IIII standards.**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS
(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.3** lb/hour **0.01** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.03 g/hr-hr** Reference: **Manufacturer information**	7. Emissions Method Code: **2**
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: **0.03g/hp-hr x 4,157 hp x 1 lb/453.6 g = 0.3 lb/hr** **0.3 lb/hr x 100 hr x 1 ton/2,000 lb = 0.01 TPY**	
11. Potential, Fugitive, and Actual Emissions Comment: **Emissions are for one generator.**	

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: **Subpart IIII NSPS**	4. Equivalent Allowable Emissions: **0.3** lb/hour **0.01** tons/year
5. Method of Compliance: **Manufacturer certification of applicable Subpart IIII standards.**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions ____ of ____

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

Allowable Emissions Allowable Emissions ____ of ____

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

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **PM10**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.3** lb/hour **0.01** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.03 g/hr-hr** Reference: **Manufacturer information**	7. Emissions Method Code: **2**
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: **0.03 g/hp-hr x 4,157 hp x 1 lb/453.6 g = 0.3 lb/hr** **0.3 lb/hr x 100 hr x 1 ton/2,000 lb = 0.01 TPY**	
11. Potential, Fugitive, and Actual Emissions Comment: **Emissions are for one generator.**	

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: **Subpart IIII NSPS**	4. Equivalent Allowable Emissions: **0.3** lb/hour **0.01** tons/year
5. Method of Compliance: **Manufacturer certification of Subpart IIII standards.**	
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):	

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 1 of 1

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: **100** % Maximum Period of Excess Opacity Allowed: **60** min/hour	
4. Method of Compliance: **DEP Method 9**	
5. Visible Emissions Comment: **Rule 62-296.320(4)(b)1., F.A.C. requires 20 perdcent opacity. Excess emissions provided by Rule 62-210.700(1).**	

Visible Emissions Limitation: Visible Emissions Limitation _____ of _____

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

H. CONTINUOUS MONITOR INFORMATION

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

Continuous Monitoring System: Continuous Monitor ____ of ____

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

Continuous Monitoring System: Continuous Monitor ____ of ____

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

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
☒ Attached, Document ID: **See Air Reports** ☐ 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: **See Air Reports** ☐ Previously Submitted, Date ______

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

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: **See Air Reports** ☐ Not Applicable
2.	Good Engineering Practice Stack Height Analysis (Rules 62-212.400(4)(d) and 62-212.500(4)(f), F.A.C.): ☐ Attached, Document ID: ____________ ☒ Not Applicable
3.	Description of Stack Sampling Facilities: (Required for proposed new stack sampling facilities only) ☐ Attached, Document ID: ____________ ☒ 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
