REPORT

PREVENTION OF SIGNIFICANT DETERIORATION (PSD) PERMIT REVISION AND PSD APPLICATION FOR GREENHOUSE GAS (GHG)

FLORIDA POWER & LIGHT COMPANY LAUDERDALE COMBUSTION TURBINE PEAKER PROJECT

BROWARD COUNTY, FLORIDA

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Table of Contents

List of Tables

List of Figures

List of Appendices

List of Acronyms

°F	degrees Fahrenheit
AOR	Annual Operating Report
API	American Petroleum Institute
BACT	Best Available Control Technology
Btu	British thermal unit
Btu/kWh	British thermal unit per kilowatt hour
Btu/lb	British thermal unit per pound
CAA	Clean Air Act
CCS	carbon capture and storage
CFR	Code of Federal Regulations
CH_4	methane
CO	carbon monoxide
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
CT	combustion turbine
DOE	U.S. Department of Energy
eGrid	Emissions and Generation Resource Integrated Database
EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute
F.A.C.	Florida Administrative Code
FDEP	Florida Department of Environmental Protection
FNAI	Florida Natural Areas Inventory
FPL	Florida Power & Light
FR	Federal Register
FRCC	Florida Reliability Coordination Council
ft	foot
FWC	Florida Fish and Wildlife Conservation Commission
gal/hr	gallons per hour
GEP	Good Engineering Practice
GHG	greenhouse gas
gr/100 scf	grains per 100 standard cubic feet

GS	geologic sequestration
GT	Gas Turbines, (typically referred to the older existing machines on the Project Site)
HFCs	hydrofluorocarbons
HHV	higher heating value
hp	horsepower
hr/yr	hours per year
IEC	International Electrotechnical Commission
kW	kilowatt
lb	pound
lb/MMBtu	pound per million British thermal units
MW	megawatt
N_2O	nitrous oxide
NAAQS	National Ambient Air Quality Standards
NETL	National Energy Technology Laboratory
NH_4	ammonium
NO	Nitrogen oxide
NO_2	nitrogen dioxide
NO_x	nitrogen oxides
NSPS	New Source Performance Standards
NSR	New Source Review
O_2	oxygen
PFCs	perfluorocarbons
PM	particulate matter
PM_{10}	particulate matter less than 10 microns
$PM_{2.5}$	particulate matter less than 2.5 microns
ppmvd	parts per million by volume dry
PSD	Prevention of Significant Deterioration
psi	pounds per square inch
RICE	reciprocating internal combustion engines
SAM	sulfuric acid mist
SCR	selective catalytic reduction
SDWA	Safe Drinking Water Act

SER	significant emissions rate
SF_6	sulfur hexafluoride
SIL	significant impact level
SIP	State Implementation Plan
SO_2	sulfur dioxide
TPY	tons per year
UIC	underground injection control [well]
ULSD	ultra low sulfur distillate “light oil”
USDW	underground sources of drinking water
USEIA	U.S. Energy Information Administration
VOC	volatile organic compound

1.0 INTRODUCTION

1.1 Background

Florida Power & Light Company's (FPL's) existing Lauderdale Plant is located in Broward County, Florida (see Figure 1-1) and includes two banks of 12 simple cycle gas turbines (GTs) (GT1 through GT12 and GT13 through GT24). GT Units 1 through 12 began operation in August 1970, and the commercial in-service dates for GT Units 13 through 24 were August 1972. Each bank of GTs has a nominal net capacity of 504 megawatts (MWs). GT Units 1 through 24 are authorized to operate pursuant to Florida Department of Environmental Protection (FDEP) Final Title V Permit No. 0110037-010-AV on natural gas and distillate oil.

These existing 24 GTs located in Broward County are first generation GTs that are used to serve peak and emergency demands in a quick-start manner. Each unit consists of two aeroderivative GTs coupled with a single gas flow driven turbine-electric generator. These units have low stack heights [less than 50 feet (ft)] and relatively high sulfur dioxide (SO_2) emission rates when firing distillate oil and high nitrogen oxides (NO_X) emissions rates when firing natural gas and oil as is 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 air pollutants. FPL also has 12 similar GTs at the Port Everglades Plant also located in Broward County.

FPL planned in 2013 to bring five new CTs into service at Lauderdale Plant to replace 34 of the existing GTs at Lauderdale and Port Everglades Plants and submitted an Air Construction/prevention of Significant Deterioration (PSD) application to FDEP in August 2013. A separate PSD Permit application was submitted to EPA Region 4 for Greenhouse Gases (GHGs) since FDEP did not have authority for PSD review of GHGs at the time. FDEP issued Air Permit No. 0110037-011-AC (PSD-FL-423) in April 2014 for the project but without authorization for GHGs. The GHG PSD application submitted to EPA was withdrawn since FDEP was seeking approval from EPA for authority for PSD approval for GHGs.

FPL now plans on going forward with the Project using specific combustion turbines selected for the Project. In addition, FPL has decided to keep two of the existing GTs at the Lauderdale Plant for black start capability and the generation, and black start diesel generators authorized by FDEP in the Air Construction/PSD Permit will no longer be part of the Project. This application is a revision to the FDEP Air Construction/PSD Permit to incorporate the latest CT design, change in PSD applicability for SO_2 and VOCs, and to seek PSD approval for emissions of GHGs.

1.2 Project Summary

The Project consists of five General Electric 7F.05 combustion turbines (CTs) and supporting equipment. These five CTs will be located at the Lauderdale Plant and will be referred to as the Lauderdale CT Project (the Project). The new CTs will be designated Units 6A through 6E.

Retiring and dismantlement of the existing GTs will occur after new CTs are operational in order to maintain peak service capability in south Florida. Following commercial operation of the Project, there will be no overlap of operation between the existing 22 GTs that will be decommissioned and new CTs after the Project is complete.

There will be significant benefits associated with the Project. The five new CTs will be more energy efficient than the existing 34 GTs and will provide cleaner energy to FPL's customers. For the same amount of generation, the new CTs will use 30 to 40 percent less fuel and have approximately 90 percent lower NO_X emission rates. The maximum total air quality impacts for the Project are predicted to be well below existing levels and in compliance with the new NAAQS for NO_2. 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.

Each CT will utilize inlet air cooling consisting of evaporative cooling and wet compression. Evaporative cooling systems achieve adiabatic cooling using water in the form of water evaporated from evaporative cooling media. 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, allowing additional power to be produced. Wet compression introduces water droplets near the compressor inlet resulting in increased power through compressed air cooling and increased mass flow. The CTs will use natural gas and ultra low sulfur distillate (ULSD) oil as fuel. ULSD 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 an existing pipeline. ULSD oil will be delivered to the facility by truck or pipeline and will be stored in ULSD oil storage tanks.

1.3 PSD Regulations

Under EPA review requirements, all major new or modified sources of air pollutants regulated under the 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 source is defined as any 1 of 28 named source categories that have the potential to emit 100 TPY or more, or any other stationary source 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 source that exceed the PSD SERs are also subject to PSD review. The FPL Lauderdale Plant is a major source under EPA and FDEP PSD regulations.

EPA has promulgated regulations providing that certain increases above an air quality baseline concentration level of sulfur dioxide (SO_2), particulate matter less than 10 microns (PM_{10}), particulate matter less than 2.5 microns ($PM_{2.5}$), and NO_2 concentrations that would constitute significant deterioration. Florida has adopted the EPA class designations and allowable PSD increments for SO_2, PM_{10}, $PM_{2.5}$, and NO_2.

PSD review is used to determine whether significant air quality deterioration will result from the new or modified source. Major new facilities and major modifications are required to undergo the following analysis related to PSD for each pollutant emitted in significant amounts:

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

In addition to these analyses, a new major source or major modification made to an existing major source also must be reviewed with respect to Good Engineering Practice (GEP) stack height regulations.

The EPA's PSD regulations are promulgated under Title 40, Part 51.166 of the Code of Federal Regulations (CFR) (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. 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 and Supreme Court decision. FDEP received EPA-approval on May 19, 2014, for implementing the PSD program for GHGs under Florida's State Implementation submitted to EPA on December 19, 2013 (79 FR 28607.28612).

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. Based on this guidance, PSD review for GHGs focuses on the control technology review and determination of BACT since there are no NAAQS or PSD Increments for GHGs.

For GHGs, the primary focus of PSD is 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. The BACT requirements are applicable to all regulated pollutants for which the increase in emissions from the facility or modification exceeds the PSD thresholds.

BACT is defined in 40 CFR 52.21(b)(12), as:

> *Best available control technology means an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. 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 and 61. If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results.*

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 New Source Performance Standards (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).

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.

1.4 Contents of PSD Permit Revision/PSD Application for GHGs

This PSD Permit Revision and PSD Application Report for GHGs is divided into four major sections.

- Section 1.0 presents an introduction to the Project.
- Section 2.0 presents a description of the Project, including the proposed CT design and associated GHG emissions.
- Section 3.0 presents a summary of the BACT analysis submitted for Air Permit No. 0110037-011-AC (PSD-FL-423) and a control technology review including a BACT analysis for SO_2 and GHGs.
- Section 4.0 presents an updated Air Modeling Analysis to confirm previously modeling analyses and demonstrate compliance with applicable air quality standards using two existing GTs for generation,
- Appendix A: Detailed Air Emissions Calculations
- Appendix B, which consists of FDEP Form No. 62-210.900(1): Application for Air Permit – Long Form.

2.0 PROJECT DESCRIPTION

2.1 Facility Description

The existing Lauderdale Plant is located within the City of Dania Beach, in Broward County, Florida, within approximately 392 acres of land owned by FPL. The facility has access from Southwest 42nd Street and Griffin Road. 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 ULSD oil usage is up to 500 hr/yr (base load equivalent hours). This is an accepted operating assumption for permitting simple-cycle CTs in Florida.

2.3 Project Emission Units

The Project's GHG emission units are:

- Five simple cycle CTs
- Fire water pump diesel engine
- Circuit breakers containing sulfur hexafluoride (SF_6)

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

Estimated emissions for the GE 7F.05CTs of non-GHG pollutants are presented in Tables 2-1 and 2-2, respectively, for natural gas and ULSD oil firing. Maximum potential annual emissions for the CTs are calculated for regulated air pollutants using a turbine inlet temperature of 59°F using evaporative cooling and wet compression. The CT performance using evaporative cooling and wet compression is relatively constant from 59^o F to 95^o F (or about a 2% output over the range). A turbine inlet temperature of 59°F is conservative, since the annual average temperature is about 75°F. To produce the maximum annual emissions, it is assumed that each CT would operate for 3,390 hours. 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 for reliability purposes. Table 2-3 presents a summary of potential emissions for various operating conditions such as turbine inlet temperature of the CTs.

A process flow diagram of the new CT configuration operating at base load conditions with a compressor inlet temperature of 59°F is presented in Figure 2-2.

A fundamental objective of the Project is to replace existing, first generation peaking capability in south Florida while reducing NO_X emission rates. The GE 7F.05 has been selected for the Project meeting the requirements of BACT established by the FDEP Air Construction/PSD Permit. This will be achieved by state-of-the-art CT combustion technology that has NO_X emission rates that achieve BACT emission levels for simple cycle CTs while rapidly producing highly efficient peaking generation. Therefore the CTs will achieve NO_X concentrations determined as BACT while achieving emission limits of CO and VOCs also established as BACT. For the Project, the GE 7F.05 CTs will achieve NOx 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. In addition, for CO, the CTs when operating a base load will achieve 4 ppmvd corrected to 15 percent O_2 when firing natural gas and 9 ppmvd corrected to 15 percent O_2 when firing ULSD oil. Corresponding VOC emissions must achieve emission rates of 1.4 ppmvw at base load operation when firing natural gas and 3.5 ppmvw when firing ULSD oil.

The black start diesel generator authorized by FDEP Permit No. 0110037-011-AC (PSD-FL-423) will not be constructed since two of the 24 existing gas turbines will be kept to provide this black start capability and generation. Black start capability is necessary at the Lauderdale Plant to provide power to start the new CTs. This circumstance primarily occurs during catastrophic events such as hurricanes.

The Project will be equipped with a 300 horsepower (hp) fire pump engine using ULSD oil. This engine will be used when necessary during emergency events such as fires. Estimated emissions and manufacturer's information for the fire pump engine, based on 100 hr/yr operation for permitting purposes are presented in Table 2-4. The fire pump engine will typically be operated only one to two hours per month for maintenance and reliability testing.

SF_6 is an electrical insulator and interrupter in equipment that transmits and distributes electricity. SF_6 has been broadly used in the U.S. due to its dielectric strength and arc-quenching characteristics and has replaced flammable insulting oils. The Project will have nine circuit breakers.

Circuit breakers associated with the Project are estimated to contain approximately 225 lbs of SF_6. Based on the guaranteed leak rate, not to exceed 0.5 percent/year, the estimated GHG emissions from the circuit breakers are as follows:

- 225 lb SF_6 x 0.005 leakage/year = 1.125 lb SF_6/year
- 1.125 lb SF_6/year x 23,900 equivalent carbon dioxide (CO_2e)/lb SF_6 (Table A-1, 40 CFR Part 98) = 26,887.5 lb CO_2e (13.44 tons CO_2e)

ULSD oil will be either trucked or piped to the facility and stored in ULSD oil tanks at the facility.

The fuel oil storage tanks are estimated to emit 1.1 tons per year (TPY) of VOC emissions. GHG emissions for the fuel oil storage tank were evaluated by reviewing EPA guidance regarding greenhouse gas emissions reporting for the petroleum and natural gas industry, including the final rule for *Mandatory Reporting for Greenhouse Gases: Petroleum and Natural Gas Systems* (dated November 30, 2010, accessed at http://www.gpo.gov/fdsys/pkg/FR-2010-11-30/pdf/2010-28655.pdf). This rule was based on technical considerations discussed and evaluated in the background Technical Support Document (EPA-HQ-OAR 2009-0923, accessed at http://www.epa.gov/climatechange/_emissions/downloads10/Subpart-W_TSD.pdf). The technical support document compiled and summarized information from a number of supporting references, including an American Petroleum Institute (API) study which specifically addresses potential GHG emissions resulting from standing and working losses from liquid petroleum storage tanks. This study, titled *Compendium of GHG Emissions Estimation Methodologies for the Oil and Gas Industry* (dated August 2009, accessed at http://www.api.org/ehs/climate/new/upload/2009_ghg_compendium.pdf, pages 5-55 to 5-56) indicates that "Unless site-specific data indicate otherwise, 'weathered' crude and other refined petroleum products are assumed to contain no CH_4 [methane] or CO_2 [carbon dioxide]. Therefore, it is also assumed that there are no CH_4 or CO_2 emissions from the working and breathing losses of tanks containing 'weathered' crude or other petroleum products." Similarly, EPA's study entitled *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry* (dated October 2010, accessed at http://www.epa.gov/nsr/ghgdocs/refineries.pdf, page 10) also concluded that petroleum liquid storage tanks will generally have negligible GHG emissions. Thus, GHG emissions for the fuel oil storage tank were considered negligible.

2.4 Annual Emissions for the Project including GHGs

On June 3, 2010, EPA promulgated regulations related to PSD 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, CH_4, nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and 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 25 tons of CO_2e and one ton of N_2O equivalent to 298 tons of CO_2e.

GHGs for the CTs were calculated based on the actual annual heat input and emission factors from 40 CFR 75, Appendix G for CO_2 and 40 CFR Part 98, Subpart C. These GHG emissions are presented in Table 2-5 and show the total annual CO_2e emissions for these pollutants. Table 2-6 presents the GHG emissions from the fire pump engine using emission factors from 40 CFR 75, Appendix G for CO and 40 CFR Part 98, Subpart C. A summary of the GHG emissions for the Project are presented in Table 2-7

PSD review is required for GHG emissions greater than the listed PSD threshold of 75,000 tons CO_2e and PSD is triggered for a non-GHG pollutant.

For PSD applicability purposes, the potential emissions from the Project are compared to PSD Significant Emission Rates in Table 2-8. This is consistent with FDEP Rule 62.212.400(2)(a)2. Since two of the existing GTs will remain for black start capability and generation, no emissions decreases are being assumed to occur for 22 of the existing GTs. Therefore, potential emissions from the project are being compared to the PSD Significant Emission Rates. The only change in additional PSD applicability in this approach from that considered in the Air Construction/PSD Permit is that PSD review is triggered by SO_2 emissions. Therefore, additional information on BACT and air quality impacts is being provided for SO_2. However, the selection of the GE 7F.05 results in VOC emissions that are less than the PSD significant emission rates and therefore PSD review is not applicable. Nonetheless, the GE 7F.05 can meet the emissions limits established in the FDEP Permit.

Table 2-9 presents a summary of emissions for hazardous air pollutants (HAPs). The Lauderdale Plant is a major source of HAPs based on the major source threshold of potential emissions of 10 tons/year or more for a single HAP or 25 tons/year or more for total HAPs. The Project's HAP emissions as shown in Table 2-9 are less than the major source thresholds for HAPs.

2.5 Suggested Revisions/Updates to Air Construction/PSD Permit

The following are suggested revisions and updates to the FDEP Permit No. 0110037-011-AC (PSD-FL-423). These suggestions do not materially change the emission limits or the BACT determinations. Rather, these suggested revisions and updates better reflect the current Project including using the GE 7F.05 CT.

- Section 2. Administrative Requirements –
  - Condition 12 - Shutdown of Existing GT Units: Upon commercial operation of Units 6A through 6E (EU045 through 049), 22 of the existing GT units (EU003 and 015) shall no longer be used to provide peaking generation to FPL's system. Two existing GTs from EU003 through EU 015 will be kept for black start capability and generation at the facility. The Title V permit revision required by **Condition 10** of this section shall contain the designation of those GTs that will remain as black start capability and those GTs that no longer will be in service. ~~The two existing CTs used for black start capability will be limited to 100 hours of operation for testing and maintenance proposes per year. If four emergency generators are installed (EU050), then the Title V revision required by **Condition 10** must contain the required information for the four emergency generators.~~

[Application 0110037-011-AC; Rules 62-210.200 (Potential to emit) and 62-212.400 (BACT), F.A.C.]

- Conditions 13 through 18 involving pre-construction ambient monitoring should be deleted as these are no longer necessary.

- Section 3. Emissions Unit Specific Conditions – A. Simple Cycle CT (EU ID No. 045 to 049)
  - Emission Unit Description – Edits suggest that are for the specific CT:
    - The CT being ~~evaluated~~ proposed for the Project ~~include~~ are the General Electric (GE) 7F.05 ~~and 7FA.04 models and the Siemens Power Generation, Inc. (Siemens) SGT6-5000F(5) model, i.e., F5, or other vendor equivalents~~. Each CT ~~may~~ will utilize inlet air cooling that may consist of evaporative cooling and wet compression~~or an alternative system~~.
    - GE 7F.05 CT: ~~1,990.3~~ 2,089.1 MMBtu/hr when firing natural gas and ~~2,121.3~~ 2,211.3 MMBtu/hr when firing fuel oil, based on a compressor inlet air temperature of ~~35~~ 59 Fahrenheit (°F), evaporative cooling and wet compression, 60 percent (%) relative humidity, 14.7 pounds per square inch (psi) pressure, the lower heating value (LHV) of each fuel and 100% load. ~~This GE CT model represents the worst case scenario with regard to heat input and emissions.~~
    - Delete reference to Siemens CT.
  - Condition 1. BACT Determinations: Determinations of the Best Available Control Technology (BACT) were conducted for nitrogen oxides (NOX), carbon monoxide (CO), particulate matter (PM/PM10/PM2.5) and sulfur dioxide (SO_2) ~~volatile organic compounds (VOC)~~. [Rule 62-210.200 (BACT), F.A.C.] *The PSD applicability for SO_2 and VOC changed with the specific CT and keeping two existing GTs.*
  - Condition 4. Combustion Turbines: The permittee is authorized to install, tune, operate, and maintain five GE 7F.05~~, GE 7FA.04, Siemens F5 or other vendor equivalents~~ CTs with a nominal generating capacity of 200 MW/each and an inlet air filtration system with inlet air cooling (~~such as~~ evaporative cool~~ers~~ing and wet compression). The CT will be designed for operation in simple cycle mode and will have dual-fuel capability (natural gas and ULSD fuel oil). [Application 0110037-011-AC; Design]
  - Condition 11.
    - NO_x Gas – Change 77 lb/hour to 73.8 lb/hour
    - NO_x Oil – Change 378.0 lb/hour to 382 lb/hour
    - CO Gas – Change 21.0 lb/hour to 20.0 lb/hour
    - CO Oil – Change 49.0 lb/hour to 49.6 lb/hour
    - SO – Change Basis from Reasonable Assurance to BACT
    - VOC - Change Basis from BACT to Reasonable Assurance
    - VOC Gas – Change 3.77 lb/hour to 3.4 lb/hour

- VOC Oil – Change 8.0 lb/hour to 8.4 lb/hour
- Footnote a – NO_x and CO concentrations emission standards are expressed in parts per million by volume, dry, corrected to 15 percent oxygen, abbreviated as ppmvd @15% O2; CO concentration emission standards pursuant to **Specific Condition 14 (100 to 90 percent load); CO emissions for other loads when compliance with NOx emissions are achieved shall not exceed 29 lb/hr when firing natural gas and 62 when firing ULSD oil.** ~~are expressed as ppmvd (uncorrected)~~.
- Footnote b - The mass emission rate standards in pounds per hour (lb/hour) are based on a turbine inlet condition of 59 ~~35~~ °F and evaporative cooling and wet compression~~using the higher heating value (HHV) of the fuel~~. Mass emission rate shall be adjusted to actual test conditions in accordance with the performance curves and/or equations provided to the Department pursuant to **Specific Condition 9** above.

o Section 3. Emissions Unit Specific Conditions B. For Nominal 3,100 kW Emergency Generators (EU ID No. 050) – This emission unit can be deleted.

3.0 CONTROL TECHNOLOGY DESCRIPTION

3.1 BACT for NO_x, $PM_{10}/PM_{2.5}$, CO, VOCs, SO_2 and SAM

FDEP issued Air Permit No. 0110037-011-AC (PSD-FL-423) and determined BACT for NO_x, $PM_{10}/PM_{2.5}$, CO, and VOCs. FDEP determined that 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 $PM/PM_{10}/PM_{2.5}$ and other fuel bound contaminants such as SO_2 and sulfuric acid mist (SAM). Combustion controls will minimize the formation of NO_x and the formation of CO and VOCs by combustor design. NO_x reduction will be achieved by water injection during oil firing. Emission limits established in the FDEP permit using the combination of these techniques has been determined to represent BACT based on an evaluation of available and feasible control technologies, and the economic, energy, and environmental impacts of control technologies. This section provides an overview of the BACT analysis presented in the application for which the FDEP permit was issued. Since the specific CT has been selected this information is being presented to reaffirm the BACT analysis for NO_x, $PM_{10}/PM_{2.5}$, CO, and VOCs, as well as SO_2 and SAM. As shown in Table 2-8, PSD review is no longer applicable for VOCs but will achieve emissions determined to be BACT in the permit.

3.1.1 NO_x

The "Top Down" BACT analysis presented in the July 2013 application was performed for the following alternatives:

1. Selective catalytic reduction (SCR) and advanced dry 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
2. Advanced dry 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

Using the GE 7F.05 CT, the NO_x emissions are limited to 9 ppm corrected to 15 percent O_2 and less than 0.23 lb/MW-hr when natural gas firing under baseload to low load compliance (approximately 46%) conditions. NO_X from oil firing will be controlled using water injection (42 ppmvd corrected to 15 percent oxygen). These include the use of wet compressions. Emission limits representing this combination of control technologies was determined to be BACT for the following reasons:

1. SCR was rejected based on technical, economic, environmental, and energy considerations and the use of control technologies that would minimize emissions of NO_x.
2. The estimated incremental cost of SCR was estimated to be over $20,000 per ton of NO_X removed. There is no change in the basis of the cost estimates presented in the July 2013 application as the mass flow of the GE 7F.05 using wet compressions is within the range of mass flows evaluated with SCR for the CTs being considered for the Project. The GE 7F.05 has a mass flow of 4,272,000 lb/hr while the range of CTs evaluated had mass flows between 4,130,000 lb/hr (GE) and 4,576,438 lb/hr (Siemens). Therefore the specific CT is within the range evaluated for SCR.

3. Additional environmental impacts would also 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 specifically related to the Project:
   a. The Project replaces 34 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 about 44 TPY per unit. Additional particulate matter may be formed through the reaction of ammonia and sulfur oxides forming ammonium salts. About 6.2 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 8.6 TPY of criteria pollutants. Additional emissions of carbon dioxide would also result.
4. There would be considerable energy impacts with applying hot SCR on the Project. The energy impacts of SCR will reduce potential electrical power generation by more than 7.7 million kilowatt hours (kWh) per year. This amount of energy is sufficient to provide the monthly electrical needs of 649 residential customers.

Emission limits established as BACT (i.e., dry low-NO_x combustion) in the FDEP Permit provides the most cost effective control alternative, is pollution preventing, and results in low environmental impacts (less than the significant impact levels for most air pollutants). Dry low-NO_x combustion at the emissions levels for the GE 7F.05 CT 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.

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 light oil firing. The GE 7F.05 selected for the Project will meet and be lower than these emissions limits.

3.1.2 CO

The BACT emission limits in the FDEP Air Construction/PSD Permit for CO are 4 ppmvd corrected to 15% O_2 when firing natural gas and 9 ppmvd corrected to 15% O_2 when firing distillate oil at baseload conditions. The GE 7F.05 CT can meet these emission limits based on manufacturer guarantees.

Emission limits using catalytic oxidation, a technically feasible alternative, were not determined to be BACT in the FDEP Permit. These were considered unreasonable for the following reasons as stated in the July 2013 analysis:

1. Catalytic oxidation will not produce measurable reduction in the air quality impacts
2. The economic impacts would be 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)

Emission limits representing combustion design and actual tests were considered as BACT in FDEP determination of the CO emission limits in the Permit. There would also be technical and economic consequences of using catalytic oxidation on CTs. Catalytic oxidation is considered in the July 2013 application to be unreasonable since it will not produce a measurable reduction in the air quality impacts. The air quality impacts are still insignificant as demonstrated in the modeling analysis. The cost of an oxidation catalyst would be significant and not be cost effective given the maximum proposed emission limits.

3.1.3 $PM/PM_{10}PM_{2.5}$

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- 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 [about 10 pounds per hour (lb/hr) when firing natural gas]} 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. The FDEP Permit established the use of natural gas with a sulfur content not to exceed 2.0 grains/100 scf and ULSD oil with an opacity limit of 10 percent as BACT.

3.1.4 Sulfur Oxides (SO_2 and H_2SO_4 Mist)

Similar to the BACT determination for emissions of PM/PM_{10}/$PM_{2.5}$, the use of clean fuels, characterized by low sulfur and trace contaminant contents, results in negligible SO_2 and H_2SO_4 Mist (SAM) emissions. For SO_2 emissions, Subpart KKKK requirements limit emissions to 0.9 lb/MW-hr or a potential total sulfur content equivalent to 0.06 lb/MMBtu if multiple fuels are fired. For the Project, the SO_2 emissions are less than about 0.06 lb/MW-hr when firing natural gas and about 0.03 lb/MW-hr when firing ULSD oil. Natural gas and ULSD oil are the cleanest fuels available with maximum sulfur contents of 2 gr/100 scf for natural gas and 0.0015 percent sulfur for ULSD oil. SO_2 and sulfuric acid mist emission limits based on use of natural gas and ULSD oil have been established as BACT in previous PSD permits.

3.2 BACT for GHGs

3.2.1 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.

As described in Section 3, BACT cannot be less stringent than any applicable NSPS. There is currently no NSPS applicable to the Project for GHGs. EPA re-proposed NSPS for electricity utility units on January 8, 2014 that will not like be finalized till will into 2015. However, it is not expected that the NSPS would apply to the Project since the NSPS would be applicable only to stationary combustion turbines that actually supply one-third of its potential electric output to a utility grid on a 3-year rolling basis as shown below:

> **§ 60.5509 Am I subject to this subpart?**
> (2) A stationary combustion turbine that has a design heat input to the turbine engine greater than 73 MW (250 MMBtu/h), combusts fossil fuel for more than 10.0 percent of the average annual heat input during a 3 year rolling average basis, combusts over 90% natural gas on a heat input basis on a 3 year rolling average basis, and was constructed for the purpose of supplying, <u>and supplies, one-third or more of its potential electric output and more than 219,000 MWh net-electrical output to a utility distribution system on a 3 year rolling average basis.</u>

Although the maximum potential operating hours requested is 3,390 hr/yr or 39.7 percent, the Project's CTs will not provide one-third of its electric output to the gird based on historical operation of FPL's simple cycle peaking units. This was recognized in EPA's preamble to the proposed regulation by stating: "simple cycle combustion turbines that are generally designed for operation during peak demand will usually supply less than one-third of their potential electric output to the grid, would not be affected by today's proposal." 79 FR 1445. In addressing the applicability concerns related to peaking units, EPA went on to say: "The EPA believes the combination of the actual sales criteria and the three year rolling average to determine if the sales criteria are met will address this concern." 79 FR 1445. Therefore, the proposed NSPS is not an applicable criteria for using as an emission limit being considered for simple cycle peaking units. EPA Region 4 also expressed this conclusion in the final GHG PSD permit for Shady Hills Generating Station a two simple cycle GE 7F.05 CTs (Prevention of Significant Deterioration Permit for Greenhouse Gas Emissions Permit PSD-EPA-R4013, United States Environmental Protection Agency, Region 4, Atlanta, Georgia, dated 1/14/14).

NSPS are applicable to the fire pump engine. For the Project, the fire pump engine meets the definition of “emergency stationary internal combustion engine” in NSPS Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines.

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

3.2.2 Definition of the Project

In recent permitting actions, the FDEP has established BACT for heavy-duty simple-cycle industrial CTs like the ones proposed for this Project. These decisions established emission rates that were achieved through the use of advanced low-NO_x 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, sulfur acid mist (SAM), PM_{10}, and $PM_{2.5}$. The BACT proposed for the Project's non-GHG emissions are consistent with these recent FDEP permits.

The Project CTs must have two modes of operation (dual fuel) and the basis of the Project is to replace 34 of the existing GTs with CTs achieving emission performance that would be determined by FDEP to be BACT for NO_x with correspondingly low CO emission rates. The CTs and other emission units non-GHG pollutant basis is summarized below:

CTs—Natural Gas-Fired

- The CTs must 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 must achieve 4 ppmvd corrected to 15 percent O_2 at base load and good combustion practices will be utilized.

CTs—ULSD Oil-Fired

- The CT must 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 must achieve 9 ppmvd corrected to 15 percent O_2 at base load and good combustion practices will be utilized.

The purpose of the Project is to replace existing 40+ year old GTs with five new CTs going into service by December 31, 2016, continuing to provide emergency and peaking duty service for FPL's electric system. Emergency and peaking duty service refers to meeting the needs of power generation when there is an electric demand caused by unit outages or system electric disruptions, and/or high electrical demand. As a result, short startup periods are required and simple-cycle CT technologies meet the requirements.

For the Project, the emergency and peaking service operation varies based on the circumstances. For emergency service, the representative average operation per CT start is less than 30 minutes with over 40 independent starts per year. For peaking service, the representative average operation is between 4 and 8 hours with over 200 starts per year. The Project's site is also a factor since its location is near the end of the natural gas transmission system where natural gas may not be available for emergency or peaking service. As a result, considerable oil operation could occur in any year.

In EPA's recently proposed "Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units," [77 Fed. Reg. 22392 (April 13, 2012)], the agency notes that peaking units "generally operate differently" than combined cycle combustion turbines. EPA points out that "simple cycle turbines are generally used much less often (and thus have lower GHG emissions) and are generally used to meet peak demand rather than base or intermediate load requirements." 77 FR 22392, 22398.

Simple cycle CTs serve a fundamentally different purpose from combined cycle CTs that are installed for intermediate and base load generation needs. This is acknowledged by EPA in the recently proposed GHG NSPS discussed above. The distinction between simple cycle units and intermediate/base load units such as combined cycle was upheld by the EPA Environmental Appeals Board on the Pio Peco Energy Center case where EPA has discretion to distinguish such purposes. Therefore the evaluation of combined cycle CTs represents re-definition of the source and as such is not included in this application.

3.3 GHG Control Technology Review – BACT Analysis

EPA issued guidance on the determination of BACT for GHGs ("*PSD and Title V Permitting Guidance for Greenhouse Gases,*" March 2011). EPA believes, in BACT reviews of GHGs, that the "top down" approach should be followed, but that it is important to consider options that improve the overall energy efficiency of the source or modification – through technologies, processes, and practices at the emitting unit. In general, a more energy-efficient technology burns less fuel than a less energy-efficient technology on a per-unit-of-output basis. Thus, considering the most energy-efficient technologies in the BACT analysis helps reduce the products of combustion, which includes not only GHGs but other regulated New Source Review (NSR) pollutants (e.g., NO_X, SO_2, $PM/PM_{10}/PM_{2.5}$, CO, etc.). Thus, EPA emphasizes that energy efficiency should be considered in BACT determinations for all regulated NSR pollutants (not just GHGs).

The following subsections provide the BACT analysis for the Project.

3.3.1 Combustion Turbines

The BACT analysis for the GHG emissions from the CTs followed the EPA suggested five-step "top down" process as described in the following subsections. Since the CTs will be identical, the emphasis of the BACT evaluation is the GHG emissions and performance of a single CT.

Step 1 – Identify all Available Control Technologies

The first step in the top down BACT process is to identify all "available" control options. Available control options are those air pollution control technologies or techniques (including lower emitting processes and practices) that have the potential for practical application to the emissions unit and the regulated pollutant under evaluation.

EPA has placed potentially applicable control alternatives identified and evaluated in the BACT analysis into the following three categories:

- Inherently Lower Emitting Processes/Practices/Designs
- Add-On Controls
- Combinations of Inherently Lower Emitting Processes/Practices/Designs and Add-On Controls

EPA recommends that the BACT analysis should consider potentially applicable control techniques from all of the above three categories.

GHGs under EPA regulations are considered as a single air pollutant, which is the aggregate group of the six principal gases, CO_2, N_2O, CH_4, HFCs, PFCs, and SF_6. CO_2 emissions result from the oxidation of carbon in the fuel. CH_4 emissions result from incomplete combustion and N_2O emissions result primarily from the temperature of combustion. CO_2, N_2O, and CH_4 are the GHGs that will be emitted from the CTs.

EPA recommends that permit applicants and permitting authorities should identify all “available” GHG control options that have the potential for practical application to the source under consideration. In its PSD and Title V Permitting Guidance for GHGs, EPA emphasizes two mitigation approaches for CO_2: 1) energy efficiency and 2) carbon capture and storage (CCS).

The GHG emissions from the Project will also include CH_4. However, emissions of CH_4 from CTs are less than 0.04 percent of the total CO_2e GHG emissions. As a result, control options for these pollutants are not practicable although an oxidation catalyst system can potentially reduce CH_4 emissions.

Project Timing and Construction

Existing gas turbines cannot be dismantled until the new CT replacement generation is constructed and in operation. The simple cycle GTs serve as emergency and peaking backup for FPL’s system and are required to remain in-service until the new CTs can take their place. Therefore, the infrastructure of the existing GTs must remain. As shown in Figure 2-1, the new CTs will be constructed in the vicinity of the north bank of 12 existing GTs. The south bank of existing GTs is located south of the cooling canal and adjacent to the existing combined cycle unit. There is insufficient space to construction the new CTs in this location. Please also note that the cross-hatched area just north of the construction area and stormwater pond is a dedicated conservation area where no facilities can be constructed.

Clean Fuels

The combustion of natural gas has the lowest emissions of GHGs of any fossil fuel and emits almost 30 percent less CO_2 than oil, and about 45 percent less CO_2 than coal (source: www.naturalgas.org). The fuels for the CTs will be natural gas and ULSD oil. It is important to recognize that the definition of BACT in 40 CFR 52.21(b)(12) includes use of “clean fuels” as a pollution control technique. The EPA PSD and Title V Permitting Guidance for GHGs states that clean fuels which would reduce GHG emissions should be considered while recognizing at the same time that the BACT analysis does not need to include a clean fuel option that would fundamentally redefine the source. Therefore, the proposed CTs will be fired with “clean fuels” as included in the definition for BACT in the CAA Part 169(3).

Aeroderivative Combustion Turbines

Smaller aeroderivative CTs are available in units up to 100 MW per CT. However, the use of these CTs, if feasible, would result in increased uncontrolled emissions of NO_x and CO compared to the proposed Project, potentially resulting in selective catalytic reduction (SCR) and oxidation catalyst pollution control technology being required. The emission guarantees NO_x and CO for the aeroderivative CTs without add-on controls are higher than for the CTs being considered for the Project.

Aeroderivative CTs have typical NO_x emissions guarantees of 15 to 25 ppmvd at 15 percent O_2 and typical CO emissions guarantees of 25 to 50 ppmvd at 15 percent O_2 with the use of dry low NO_X technology. To achieve the same emission levels for NO_x and CO required for the Project, additional pollution controls to reduce NO_x and CO would be needed, e.g., SCR and oxidation catalyst. For this Project, compared to the proposed GE 7F.05 CTs, smaller CTs in this range would result in higher capital costs per MW and operating costs associated with operation and maintenance, ammonia, catalyst replacement, and lost energy through parasitic load from the SCR (backpressure and operational electrical demand of process equipment). SCR would result in additional environmental impact as a result of emissions of ammonium (NH_4) in the form of catalyst slip. In addition, the emergency service using both natural gas and ULSD oil will introduce demands that SCR cannot meet for these short durations. The use of a CO oxidation catalyst would also result in higher operating costs associated with operation and maintenance, catalyst replacement, and lost energy through parasitic load, and would convert the CO emissions to CO_2, resulting in a negligible environmental benefit. Aeroderivative CTs of this size would result in higher operating costs and additional environmental impacts of other pollutants while resulting in no significant benefit in CO_2e reduction.

The largest available aeroderivative CT is the GE LMS100 that has a capacity of 100 MW. To meet the Project’s requirements at least 10 LM100 CTs would be required. The land requirements for the LM100 CT alone are approximately the same as a single GE 7F.05 CT without consideration of the cooling requirements and installation of SCR and supporting systems. The land requirements alone would double with corresponding impacts.

Additional water is also required for aeroderivative CTs. The LMS100 requires inter-cooling which can be achieved through water or air cooling. Air cooling requires a significantly larger area than water cooling, and is less effective in southern Florida. Water for cooling and emissions control results in additional environmental impacts associated with water withdrawal and discharge.

These factors related to the LMS100 will be discussed further in Step 4.

Energy Efficiency

Energy efficiency falls under the general category of lower polluting processes/practices. Applying technologies, measures and options that are energy efficient translates not only in the reduction of emissions of the particular regulated NSR air pollutant undergoing BACT review, but it also may achieve collateral reductions of emissions of other pollutants. There are different categories of energy efficient improvements:

- Technologies or processes that maximize the efficiency of the individual emissions unit
- Options that could reduce emissions by improving the utilization of thermal energy and electricity that is generated and used onsite

When the efficiency of the power generation process is increased, less fuel is burned to produce the same amount of electricity. This provides the benefits of lower fuel costs and reduced air pollutant emissions (including CO_2). Several recent BACT determinations for GHG emissions concluded that high efficiency power generation technology is the only available and feasible control technology. Efficient peaking power production is technically feasible and is proposed for the Project.

Carbon Capture and Storage

CCS falls under the category of add-on controls, which are air pollution control technologies that remove pollutants from a facility's emissions stream. EPA suggests that CCS is an add-on pollution control technology that is "available" for large CO_2 emitting facilities including fossil fuel-fired power plants and industrial facilities with high purity CO_2 streams. As a result, EPA suggests that CCS be considered in Step 1 of the BACT analysis.

CCS is composed of three main components: CO_2 capture and/or compression, transport, and storage.

Carbon Capture – Before CO_2 gas can be sequestered, it must be captured as a relatively pure gas, so that it can be feasibly stored. Most power plants and other large point sources use air-fired combustors, a process that exhausts CO_2 diluted with nitrogen. Flue gas from natural gas combined cycle plants contains only about four percent CO_2 by volume. For effective carbon sequestration, the CO_2 in the exhaust gases must be separated and concentrated due to the low percent by volume.

The most likely options currently identifiable for CO_2 separation and capture include:

- Absorption (chemical and physical)
- Adsorption (physical and chemical)
- Low temperature distillation
- Gas separation membranes
- Mineralization and biomineralization

Carbon Transport – After the CO_2 is captured, it must be transported to a carbon sequestration site. Pipelines are the most common method for transporting large quantities of CO_2 over long distances. Shipping CO_2 via pipeline involves compressing gaseous CO_2 to a pressure above 1,160 pounds per square inch (psi), to increase CO_2 density and make it easier and less expensive to transport. A CO_2 pipeline would be similar to a high pressure natural gas pipeline and is technically possible. CO_2 also can be transported as a liquid in seagoing vessels or via tankers on roads or railways. In these instances, the CO_2 is held in insulated tanks at low temperatures and relatively low pressures.

Carbon Storage – In a CCS system, CO_2 is captured, it is transported, if necessary, and then stored. Geologic formations such as depleted oil and gas reservoirs, unmineable coal seams, and underground saline formations are potential options for long term storage. Pressurized CO_2 is injected into the deep geologic formations through drilled wells. Under high pressure, CO_2 turns to liquid and can move through a formation as a fluid. Once injected, the liquid CO_2 tends to be buoyant and will flow upward until it encounters a barrier of non-porous rock, which can trap the CO_2 and prevent further upward migration. When CO_2 is injected into a coal seam, it is adsorbed onto the coal surfaces, and methane gas is released and produced in adjacent wells. There are other mechanisms for CO_2 trapping as well: CO_2 molecules can dissolve in brine, react with minerals to form solid carbonates, or adsorb in the pores of the porous rock.

Deep saline formations, which are layers of porous rock saturated with brine, present an enormous potential for geologic storage of CO_2. However, there is not much experience with saline formations such as that acquired through resource recovery from oil and gas reservoirs and coal seams. There is ongoing research focused on storage in organic rich shale, which is a thin horizontal layer of sedimentary rock with low vertical permeability and in basalt formations, which are geologic formations of solidified lava. Other possible options include liquid storage in deep ocean areas.

The paper “Realistic Costs of Carbon Capture” provides cost comparisons for electric generation using CCS (Harvard Kennedy School, July 2009). As provided in Annex C using data from National Energy Technology Laboratory (NETL), Electric Power Research Institute (EPRI) and SFA, the range of avoided cost in dollars per metric ton of CO_2 separated is from \$63 to \$83 equivalent to \$70 to \$93 short tons of CO_2 separated, based on two advanced natural gas-fired F class turbines. Based on a cost of \$70 per short ton of CO_2, and an estimated annual CO_2 rate of 450,000 short tons from each of the Project’s CTs, the annual cost for separation alone would be over \$30 million/CT. This cost assumes that the separation equipment could be operational during the short operational periods required for the Project. Additionally per footnote of Annex C, this cost does not include expenses associated with transportation, injection and storage.

The maximum potential emissions of CO_2 for each CT were estimated to about 494,552 tons per year (TPY) including distillate oil firing (Table 2-5). Assuming 90 percent CO_2 removal, the annualized cost for CO_2 would be calculated at \$67.40 per ton of CO_2 removed and sequestered. This cost however is based on estimates for a combined cycle unit where exhaust temperatures are about 93^{o}C (200^{o}F). The cost for additional exhaust gas cooling would have to be considered. Moreover, as discussed later, the representative number of start and shutdowns would be 240 per year, with considerable number starts (i.e., 40) involving only 30-minute operation. The ability of cooling and absorption equipment to handle this cycling has not been technically demonstrated.

Oxidation Catalyst

Catalytic oxidation technology, which is primarily designed to reduce CO emissions, will also reduce CH_4 emissions but to a lesser extent. Oxidation catalysts operate at elevated temperatures where excess O_2 in the exhaust reacts with CH_4 to form CO_2. As a result, 25 lb of CO_2e are reduced to 2.75 lb of CO_2. At the very best only about 87 percent of the CO_2e could be reduced. Assuming a 90 percent removal of CH_2 the maximum control is only about 80 percent removal of CO_2e.

The total amount of CO_2e resulting from CH_4 emissions is only 0.06 percent of total CO_2e emissions and is about 282 tons CO_2e/CT. The secondary emission caused by the backpressure was estimated to be over 900 tons of CO_2. (See Table 4-4 in the original Air Construction Permit Application for the FPL Lauderdale Combustion Turbine Project, Broward County, July 2013 submitted to FDEP). This clearly demonstrates the infeasibility of an oxidation catalyst to control CH_4 emissions.

Step 2 – Identification of Technically Feasible Control Alternatives

Under the second step of the top down BACT analysis, a potentially applicable control technique listed in Step 1 may be eliminated from further consideration if it is not technically feasible for the specific source under review. EPA considers a technology to be potentially applicable if it has been demonstrated in practice or is available.

Energy Efficiency

Efficient power generation is technically feasible and is being proposed for the CTs. This is discussed in detail in Step 4.

Carbon Capture and Storage

In its PSD and Title V permitting guidance for GHGs, EPA states that it does not believe CCS will be a technically feasible BACT option in certain cases at this time. To establish that an option is technically feasible, the permitting record should show either that an available control option has been demonstrated in practice or is available and applicable, with the term “applicable” generally meaning a technology can reasonably be installed and operated on the source type under consideration. EPA recognizes the significant logistical hurdles that the installation and operation of a CCS system presents and that set it apart from other add-on controls that are typically used to reduce emissions of other regulated pollutants. In addition, other add-on controls typically have an existing accessible infrastructure in place to address waste disposal and other offsite needs. It should also be noted that while CCS may be available according to EPA, it is not “commercially available.” All current CCS projects for power plants are primarily in the demonstration stage.

Logistical hurdles for CCS may include obtaining contracts for offsite land acquisition (including the availability of land), the need for funding (including, for example, government subsidies), timing of available transportation infrastructure, developing a site for secure long-term storage and environmental permitting for underground GHG sequestration. Not every source has the resources to overcome the offsite logistical barriers necessary to apply CCS technology to its operations.

There are no CCS systems commercially available for full-scale power plants in the United States. On February 3, 2010, President Obama established an Interagency Task Force on Carbon Capture and Storage, composed of 14 Executive Departments and Federal Agencies. The Task Force delivered several recommendations to the President on August 12, 2010. The Task Force, co-chaired by the U.S. Department of Energy (DOE) and the EPA, recommended a comprehensive and coordinated strategy to overcome the barriers to the widespread, cost effective deployment of CCS within ten years, with a goal of bringing five to ten commercial demonstration projects online by 2016. These projects, to be deployed with the help of federal funding, are intended to demonstrate a range of current generation CCS technologies applied to coal-fired power plants and industrial facilities. The Task Force concluded that such research and development efforts were designed to reduce the cost of CCS and facilitate cost-effective deployment after 2020. However, widespread deployment of CCS will occur only if the technology is commercially available at economically competitive prices. Therefore, the application of CCS is very much in the development stage and not commercially available.

In November 2010, EPA published the final rule for Federal requirements of Underground Injection Control (UIC) for CO_2 Geologic Sequestration (GS) Wells, as authorized by the Safe Drinking Water Act (SDWA). The final rule establishes new federal requirements for the underground injection of CO_2 for the purpose of long-term underground storage, or GS, and a new well class – Class VI – to ensure the protection of underground sources of drinking water (USDWs) from injection-related activities. Therefore, authorization must be obtained from FDEP under this federally delegated program prior to GS. Permitting for a Class VI well takes many years as exploratory wells are likely required for CO_2 sequestration, including drilling deep holes, testing, etc., prior to approval of an injection well. Indeed, the exploratory well process to assess the formation can take over two years for drilling, testing, and approval of the start of an injection well process.

EPA Region IX's "Fact Sheet and Ambient Air Quality Impact Report" for the Pio Pico Energy Center presents information concluding that absorption of CO_2 requires turbine exhaust temperatures of about 50°C (about 120°F) to improve absorption and minimize solvent loss. As presented in Figure 2-2 of the application, the exhaust temperature of the CTs is about 590°C (about 1,100ºF). The CTs must have fast start capability requiring simple cycle operation that cannot be achieved in combined cycle mode that includes a heat recovery steam generator (HRSG). In their analysis, EPA Region 9 states for the Flour and BP Central Gas Facility (CGF) using CO_2 absorption by monoethanolamine (MEA):

> "The integral nature of the HRSG to the overall process for the CGF is notable because it would essentially require conversion of the turbines from simple-cycle to combined-cycle operation. Therefore, based on this information, we conclude that while carbon capture with an MEA absorption process is feasible for a combined-cycle operation, it is not feasible for simple-cycle units (*i.e.,* those without a HRSG). Given that combined-cycle gas turbines are not technically feasible for the proposed Project, as discussed above, CCS is also technically infeasible for the proposed Project."

Carbon capture systems (CCS) would require considerable space for the cooling system, CO_2 absorption systems and compression. As described above, the exhaust for a simple cycle CT would require, similar to hot SCR systems, a cooling chamber and ambient air fans to reduce the temperature. This would significantly increase the volume of gas required for CO_2 absorption and concomitant increase in absorber sizes and space requirements. Alternatively, a cooling system using water could be used but this would require a significant water quantity. The footprint for each CT would increase by 2 to 3 times and prohibit their location within the area shown in Figure 2-1.

Based on these considerations, it can be reasonably concluded that CCS is not applicable to the Project, and consequently not technically feasible.

Oxidation Catalyst

Catalytic oxidation is an available control technology for CH_4, although no approval for its use for this purpose has occurred. The oxidation catalyst will reduce CH_4 with the following reaction:

$$CH_4 + 2O_2 \rightarrow CO_2 + 2H_2O$$

While CH_4 emissions can be reduced using an oxidation catalyst, the amount of CO_2e reduced is less than 0.05 percent. Moreover, the amount of potential CO_2e that could be reduced from the Project combined cycle unit is 40 times lower than the EPA GHG thresholds. Therefore, the addition of an oxidation catalyst to the Project for GHG control is neither practicable nor feasible to reduce CH_4.

Step 3 – Rank Remaining Control Technologies

After the list of all available controls is narrowed down to a list of the technically feasible control technologies in Step 2 above, Step 3 of the top down BACT process calls for the remaining control technologies to be listed in order of overall control effectiveness for the regulated NSR pollutant under review. The most effective control alternative (i.e., the option that achieves the lowest emissions level) should be listed at the top and the remaining technologies ranked in descending order of control effectiveness.

Based on the discussion in Steps 1 and 2, the only technically feasible control option for GHGs is energy efficiency.

Step 4 – Economic, Energy, and Environmental Impacts

Under Step 4 of the top down BACT analysis, economic, energy, and environmental impacts must be evaluated for each option remaining under consideration.

The “top” control option and in the case of GHG the “top” energy reduction technology should be established as BACT unless the applicant demonstrates, and the permitting authority agrees, that the energy, environmental, or economic impacts justify a conclusion that the most stringent technology is not "achievable" in that case. If the most stringent technology is eliminated in this fashion, then the next most stringent alternative is considered, and so on.

The "top" control option for the CTs is energy efficiency. The CTs will operate in the simple cycle mode to produce electric energy during high demand periods. The CTs being considered are among the most efficient available and 40 percent more energy efficient than the existing GT technology they are replacing. The new CTs will use natural gas as the primary fuel and ULSD oil as a backup fuel. These fuels are the most efficient for this application

The efficiency of the generation technology in producing electricity in an amount necessary to meet demands and fuel utilized are the most important aspects in GHG emissions from electric generation projects. Together, efficiency, fuel type and operational dispatch/cycling dictate the amount of GHG emissions per unit of generation.

The measure of the efficiency for an electrical generating facility is the units' heat rate. Heat rate is a measurement of how efficiently a unit uses heat energy. It is expressed as the number of British thermal units (Btu) of heat required to produce a kilowatt-hour of energy based on higher heat value (HHV). A heat rate of 3,413 Btu/kWh reflects an efficiency of 100 percent from thermal energy to electrical energy.

The CTs' heat rate (or energy efficiency) was compared to data obtained from the U.S. Energy Information Administration (EIA). In 2011, there were 940 GTs with a net summer capacity of 56,032 MWs (EIA, 2012). The average tested heat rates for GTs when firing natural gas and distillate oil were (based on HHV for 2012):

- Natural gas – 11,449 Btu/kWh net (29.8 percent efficiency)
- Distillate oil – 13,662 Btu/kWh net (25.0 percent efficiency)

The Project will replace the capacity of 22 existing GTs at the Ft. Lauderdale Plant and 12 existing GTs at the Port Everglades Plant. The existing GTs at the Lauderdale and Port Everglades Plants are first-generation aeroderivative turbines using Pratt & Whitney aircraft engines. These units are configured with two gas turbines driving a single gas flow driven turbine coupled to an electric generator. The heat rates for these units are:

- Lauderdale Plant GTs: Average expected net operating heat rate of 16,585 Btu/kWh with an actual operating net heat rate of 17,511 Btu/kWh
- Port Everglades GTs: Average expected net operating heat rate of 17,405 Btu/kWh with an actual operating net heat rate of 18,705 Btu/kWh

- Average weighted expected net operating heat rate for the Lauderdale Plant and Port Everglades is 16,859 Btu/kWh

LMS100

As discussed in Step 1 of the BACT analysis, aero-derivative CTs such as the LMS100 must have the ability to meet the fundamental Project requirements. These requirements were the ability to meet low NO_X emissions without SCR, have a relatively small footprint that can be installed on the existing site, cost-effective and proven performance, and durability. The following is information regarding the economic and environmental factors for why this technology is not appropriate as BACT for this Project (i.e., Step 4).

On an economic basis, the cost differential between the GE 7F.05 CTs and aero-derivative CTs are similar to the information presented for the Shady Hills Generation Station (Golder Associates Inc. 2012. New Source Review for Greenhouse Gases, Shady Hills Generating Station/EFS Shady Hills LLC, Pasco County, Florida). In this recent analysis of the same GE CTs being considered for this Project, the cost effectiveness for aero-derivative CTs was $60.2 per ton of CO_2 reduced for the LMS100 CTs and $285.6 per ton of CO_2 reduced for LM600 CTs higher than the GE 7F.05CT. FPL considers this cost differential between aeroderivative CTs and the CTs considered for this Project to be representative for this Project.

From an environmental perspective, the aero-derivative CTs would require additional NOx controls, a larger area, gas compression and additional water compared to the larger CTs being considered for the Project.

- Additional Controls: The LMS100 has a NO_x emission rate of 25 ppmvd corrected to 15 percent oxygen compared to the 9 ppmvd corrected to 15 percent oxygen for the CTs being considered for the Project. The BACT limits for NO_x previously approved as BACT by FDEP is 9 ppmvd corrected to 15 percent oxygen for large CTs that the LMS100 cannot achieve. As a result, an SCR system would be required. This requires additional space and the use of ammonia.
- Space requirements: As shown in Figure 2-1, the footprint of the CTs being considered occupies about 5,000 square feet. In contrast, the LMS100 requires about 15,000 square feet due to the requirements for intercooling, gas compression, SCR systems and cooling systems such as cooling towers. For the Project, an additional 3.5 acres would be required. This space is not available as the northern and eastern undeveloped areas are in conservation easements and wetland mitigation projects.
- The LMS100 requires intercooling and a cooling system (such as a cooling tower) to disperse the rejected heat. For a cooling tower, at least 80,000 gallons/day/CT for cooling tower makeup would be required for this purpose. On an annual basis, about 68 million gallons/year of water would be required. To limit the buildup of salts in the cooling tower, there also would be associated cooling tower blowdown that would require disposal. Assuming five cycles of concentration, about 100,000 gallons/day of cooling tower blowdown would have to be discharged for LMS100 CTs. For the Project, the CTs being considered do not require cooling towers and no discharge is required.

The LMS100 requires increased pressure of natural gas for operation. The natural gas pressure available for the Project would have to be increased for operation of the LMS100. This will require additional gas compressions equipment. Electrical gas compressors are the only feasible alternative that matches the starting requirements for the Project. A gas compressor rated as high as 600 kW per LMS100 will be required resulting in an additional auxiliary load of 1,800 kW while in operation.

Large Frame CTs

The heat rate and efficiency of the GE 7F.05 CTs when using natural gas and ULSD oil are as follows (new and clean, 100 percent load, no inlet cooling, based on manufacturer data):

- Natural gas firing – 10,060 Btu (HHV)/kWh (34 percent efficiency) (Base load at 85^oF).
- Oil firing – 10,052 Btu (HHV)/kWh (34 percent efficiency) (Base load at 85^oF).

These estimated new and clean 100 percent load heat rates are below the approximate average heat rates for simple cycle CTs in the U.S. and much lower than the existing Lauderdale Plant and Port Everglades GTs that the new CTs will replace.

As part of EPA's clean energy initiatives, EPA developed the Emissions & Generation Resource Integrated Database (eGRID) as a resource tool in assessing GHG emissions. eGRID is a comprehensive source of data on the environmental characteristics of almost all electric power generated in the United States with data available based on a variety of geographic regions and locations. Data is also available on a plant-specific basis. Based on the latest available eGrid data, the following are the emissions of CO_2 on a generation basis for generation facilities located in the same subregion as the Project:

- Florida Reliability Coordination Council (FRCC) – 1,181.6 lb CO_2/MW-hr (net) for all generation (including nuclear), 1,368.2 lb CO_2/MW-hr for total combustion.
- FPL – 815.6 lb CO_2/MW-hr for all generation (including nuclear); 1,029.2 lb CO_2/MW-hr (net) for total combustion generation.

Step 5 – Select the BACT

In Step 5 of the BACT determination process, the most effective control option not eliminated in Step 4 should be selected as BACT for the pollutant and emissions unit under review and included in the permit.

BACT

Energy efficiency, the only remaining and feasible control technology, is selected as BACT for the GHG emissions from the Project. Energy efficiency plays a major role in affecting GHG emissions and EPA suggests that more emphasis will be given to energy efficiency in GHG BACT analysis. As demonstrated in the discussion in Step 4, the Project meets the requirements of energy efficiency under EPA's GHG BACT guidelines.

The CCS option was eliminated in Step 2 as not technically feasible for the Project. Although EPA considers CCS as available, it is not commercially available. Indeed, EPA recognizes that at present CCS is an expensive technology, largely because of the costs associated with CO_2 capture and compression. In the Guidance, EPA states that even if not eliminated in Step 2 of the BACT analysis, on the basis of the current costs of CCS, CCS would be eliminated from consideration in Step 4 of the BACT analysis, even in some cases where underground storage of the captured CO_2 near the power plant is feasible. In the case of the Project, CCS is not a technically feasible control technology based on the Project's overall purpose (replacing less efficient peaking units).

FPL proposes a gross output based GHG BACT limit based on a statistical analysis of the turbines under consideration. As described previously, the units will be operated in emergency and peaking service operation that varies substantially based on the electric needs of FPL's over 20,000 MW electric system and support neighboring utilities. During emergency service, the representative average operation per CT start is 30 minutes with over 40 independent starts per year. During peaking service, the representative average operation is between 4 and 8 hours with over 200 starts per year. The Project's location is also a factor since its location is near the end of the natural gas transmission system where natural gas may not be available for emergency or peaking service requiring considerable ULSD oil operation. Therefore GHG limits were developed for gas and ULSD oil operation over the expected loads of operation. For natural gas-firing during normal operation (loads when the CT can comply with emission limits for NO_X) the proposed GHG limit is 1,398 lb/CO_2 e/MWh calculated as follows:

Category	Units	Estimated Performance		
Fuel		Gas	Gas	Gas
Turbine Inlet	degree F	85	85	85
Evaporative Cooling		Off	Off	Off
Gross Load	%	100%	75%	Low [a]
Gross Heat Rate	Btu/kWh (HHV)	10,060	10,556	13,290
Gross Efficiency	%	33.9%	32.3%	25.7%
CO_2e	lb CO_2e/MWh	1,196	1,255	1,580
Operation		50%	25%	25%
Gas Average CO_2e	lb CO_2e/MWh	1,306	(Average of 100%, 75% and Low load)	
Performance Margin	%	2%	(Vendor Performance Margin)	
Degradation Margin	%	5%	(Account for normal wear during operation)	
Proposed CO_2e	lb CO_2e/Mwh[a]	1,398	Composite average of 720 operating hours	

[a] Load at which the CT has achieved compliance with NO_x emission limit.

The proposed GHG limit is based on operating at 50, 25, and 25 percent of the time at baseload, 75 percent load and low load conditions, respectively. “Low” load conditions are the minimum load where the CT can meet the BACT NO_x limits for gas. A total 7 percent margin was added that consisted of 2 percent vendor for performance to account for that lack of vendor guarantees over the operating range and 5 percent to account of normal degradation with time. The latter is especially important for simple cycle CTs that have numerous startups and shutdowns during operation. The 720 hour composite average operating hours, or an equivalent 30-days of operation, would encompass the range of operating conditions that the CTs would likely experience. A 12-month rolling average for peaking units would not be appropriate as some months no or limited operation could occur that would not be representative of normal operation.

For ULSD oil-firing during normal operation (loads when the CT can comply with emission limits for NO_X) the proposed limit is 1,871 lb/CO_2 e/MWh based on a composite average of 720 operating hours calculated as follows:

Category	Units	Estimated Performance		
Fuel		Gas	Gas	Gas
Turbine Inlet	degree F	85	85	85
Evaporative Cooling		Off	Off	Off
Gross Load	%	100%	75%	Low [a]
Gross Heat Rate	Btu/kWh (HHV)	10,052	10,667	12,331
Gross Efficiency	%	34.0%	32.0%	27.7%
CO_2e	lb CO_2e/MWh	1,631	1,731	2,001
Operation		50%	25%	25%
Gas Average CO_2e	lb CO_2e/MWh	1,749	(Average of 100%, 75% and Low load)	
Performance Margin	%	2%	(Vendor Performance Margin)	
Degradation Margin	%	5%	(Account for normal wear during operation)	
Proposed CO_2e	lb CO_2e/MWh[a]	1,871	Composite average of 720 operating hours	

[a] Load at which the CT has achieved compliance with NO_x emission limit.

This proposed limit does not include startups and shutdowns, fuel switches and combustor tuning. CT could have multiple startups and shutdowns in any day and as previously presented operation can be as short as 30 minutes during emergency periods. During startups and shutdowns the CT operates at very low loads with substantially higher heat rates. While startups and shutdowns periods are of short duration (typically less than 30 minutes), the lb/CO_2e is substantially higher.

The CTs selected for the Project have fast start options, which are critical to the Project's design criteria to achieve the grid response requirements. Therefore the CTs can be started in traditional start mode or fast start mode. The fast start mode is approximately 10 minutes while the traditional start is 30 minutes to 50 percent load. FPL plans the operation of CTs based on the energy demand requirements. This may include fast and traditional starts depending on the generation needed. Fast starts are intended to be used only when grid responsiveness requirements demand the quicker startup. Shutdown is approximately 10-15 minutes from 100 percent load.

It should be noted that while manufacturers have provided startup and shut down emission estimates, they are not guaranteed and are only estimated from new and clean performance. For the Project the estimated maximum startup and shutdown (SUSD) GHG emissions in lb CO_2e/MWh, which includes fuel switches and combustor tuning, are as follows based on natural gas and ULSD firing:

- 3,492 lb CO_2e/MWh when firing natural gas
- 3,451 lb CO_2e/MWh when firing ULSD oil

As previously presented the Project will replace first generation inefficient gas turbines with efficient CTs. The new CTs would emit much lower GHG emissions for the same amount of generation when compared to the existing gas turbines.

The proposed GHG limit for this Project is similar to the GHG contained in the final PSD Permit for the Shady Hill Generating Station that is using the GE 7F.05 CTs (Prevention of Significant Deterioration Permit for Greenhouse Gas Emissions Permit PSD-EPA-R4013, United States Environmental Protection Agency, Region 4, Atlanta, Georgia, Dated 1/14/14). In this draft GHG PSD permit, the GHG emission limit is 1,377 lb CO_2e/MWh for natural gas firing and 1,928 lb CO_2e/MWh for distillate oil firing.

The addition of the new CTs to FPL's fleet will further improve FPL's low GHG emission rate that is one of the lowest in the U.S. electric utility industry. Based on the analysis, the proposed BACT emission rates are appropriate for this generation replacement project.

For the composite 720 operating hour rolling proposed GHG limits, FPL is proposing a continuous monitoring and compliance method based on 40 CFR Part 60 Subpart KKKK. This NSPS is for stationary combustion turbines and includes a lb NO_x/MWh standards and methods of calculating a composite standard using multiple fuels. FPL proposes similar standards and methods for CO2e/MWH calculations. The suggested permit language is provided below:

1. Permittee shall install and certify monitoring systems required for quantifying CO_2 emissions from each CT in accordance with the applicable requirements of 40 CFR Part 75. Consistent with §75.4(b), all applicable certification tests shall be completed within 180 calendar days after the date the unit commences commercial operation (as defined in 40 CFR 72.2).

2. Following initial certification, the CO_2 continuous measurement system shall be quality assured in accordance with the applicable requirements of 40 CFR Part 75.

3. The CO_2 continuous measurement system shall be capable of producing hourly determinations of CO_2 mass emissions in tons per hour (tons/hr).

4. In accordance with §75.62, an initial monitoring plan shall be submitted identifying the methodology for which CO_2 mass emissions will be continuously monitored. The initial monitoring plan shall be submitted no later than 21 days prior to the initial certification tests.

5. Permittee shall provide notifications as specified in §75.61 for any event related to the continuous measurement of CO_2.

6. Permittee shall measure and record, for each CT, the actual heat input (Btu) on an hourly basis in accordance with 40 CFR Part 75.

7. Permittee shall measure and record, for each CT, the following on an hourly basis as described in accordance with the condition of this permit:

a. Gross energy output rate (MW);

d. CO_2 mass emission rate (tons CO_2/hr) for each CT;

e. Fuel Heat Input rate (mmBtu/hr) for each CT;

f. Unit Operating Time as described in §75.57(b)(2);

g. The type of fuel (natural gas or ULSD) burned for each CT; and

h. Time of each mode of operation: 1. Low or Higher Loads or 2. SUSD.

8. Permittee shall calculate and record, for each CT, the following on an hourly basis for each hour of operation:

a. The 720 operating hour rolling average CO_2 emission rate (lbs CO2/MWh_{gross}) calculated as the sum of each hourly CO_2 mass emission rate (tons CO_2/hr) times the unit operating time for the respective hour divided by the sum of the recorded hourly gross energy output (MWh_{gross}) for all hours of operation in the 720 operating hour period.

$$AvgCO2Rate_i = \frac{\sum_1^{720} CO2Mrate_i * t_i}{\sum_1^{720} GrossMWh_i}$$

b. The applicable composite standard for the 720 operating hour period (lb CO_2/MWh_{net}). The applicable composite standard is the average of the applicable standard for each hour of operation in the 720 operating hour period. For hours where multiple emissions standards would apply; the applicable limit for that hour is determined based on the condition that corresponds to the highest emissions standard.

$$CompositeStd = \frac{Limit_{Gas} * MWh_{Gas} + Limit_{Oil} * MWh_{Oil} + Limit_{GasSUSD} * MWh_{GasSUSD} + Limit_{OilSUSD} * MWh_{OilSUSD}}{Total\ MWh}$$

c. The 720 operating hour rolling average heat rate (Btu/kWh$_{gross}$) calculated as the sum of each hourly heat input rate times the unit operating time for the hour divided by the sum of the recorded hourly gross energy output (MWh$_{gross}$) for all hours of operation in the 720 operating hour period times 1,000.

$$AvgHeatRate_i = \frac{\sum_1^{720} HIrate_i * t_i}{\sum_1^{720} GrossMWh_i} * 1{,}000$$

3.3.2 Circuit Breakers

SF_6 is an electrical insulator and interrupter in equipment that transmits and distributes electricity. SF_6 has been broadly used in the U.S. due to its dielectric strength and arc-quenching characteristics and has replaced flammable insulating oils.

Circuit breakers associated with the Project are estimated to contain approximately 225 lbs of SF_6. Based on the guaranteed leak rate, not to exceed 0.5 percent/year, the estimated GHG emissions from the circuit breakers are as follows:

- 225 lb SF_6 x 0.005 leakage/year = 1.125 lb SF_6/year
- 1.125 lb SF_6/year x 23,900 CO_2e/lb SF_6 (Table A-1, 40 CFR Part 98) = 26,887.5 lb CO_2e (13.44 tons CO_2e)

Step 1 – Identify All Available Control Technologies

The first step in the top down BACT process is to identify all "available" control options. Available control options are those air pollution control technologies or techniques (including lower emitting processes and practices) that have the potential for practical application to the emissions unit and the regulated pollutant under evaluation.

The available control options include alternative (non-SF_6) dielectric fluids and minimizing the fugitive emission of SF_6. Historically dielectric fluids such as dielectric oils have been used in high voltage applications. However, the use of these materials in circuit breakers has been predominately replaced with SF_6 that has excellent dielectric and arc-quenching properties and is not flammable.

Modern SF_6 circuit breakers are designed as totally enclosed-pressure systems with low potential SF_6 fugitive emissions. Leakage is typically no more than 0.5 percent by weight. It should be recognized that the actual leakage rate is likely 0.1 percent by weight based on EPA's SF_6 Emission Reduction Partnership. In addition, circuit breakers have alarms that provide a warning if a leak is occurring and corrective action is necessary. In addition, this equipment is routinely inspected to verify proper operation since this equipment is necessary for the safe operation of the CTs.

Step 2 – Identification of Technically Feasible Control Alternatives

Under the second step of the top down BACT analysis, a potentially applicable control technique listed in Step 1 may be eliminated from further consideration if it is not technically feasible for the specific source under review. EPA considers a technology to be potentially applicable if it has been demonstrated in practice or is available.

Circuit breakers using SF_6 with alarms and periodic inspections are technically feasible for the Project. The use of alternative dielectric fluids is not practicable for high-voltage applications. Circuit breakers using SF_6 are presently superior in their performance to alternative systems such as dielectric oil, high pressure air blast or vacuum circuit breakers. Moreover, EPA's SF_6 Partnership has recognized that there is no clear alternative to using SF_6 and fugitive emissions are reduced by implementing detection, repair and replacement strategies [EPA, 2011; (SF_6 Emission Reduction Partnership for Electric Power Systems, 2010 Annual Report, December 2011)].

Step 3 – Rank Remaining Control Technologies

After the list of all available controls is narrowed down to a list of the technically feasible control technologies in Step 2 above, Step 3 of the top down BACT process calls for the remaining control technologies to be listed in order of overall control effectiveness for the regulated NSR pollutant under review. The most effective control alternative (i.e., the option that achieves the lowest emissions level) should be listed at the top and the remaining technologies ranked in descending order of control effectiveness.

The most effective control of fugitive SF_6 emissions is using a totally enclosed system equipped with leak detection, periodic inspections and maintenance. The expected guarantee meets the requirements of the International Electrotechnical Commission (IEC) standard of 0.5 percent (IEC Standard 62271-1, 2004) that is recognized by the EPA's SF_6 Reduction Partnership as an effective criterion for minimizing fugitive SF_6 emissions.

Step 4 – Economic, Energy, and Environmental Impacts

Under Step 4 of the top down BACT analysis, economic, energy, and environmental impacts must be evaluated for each option remaining under consideration.

The "top" control option and in the case of GHG the "top" energy reduction technology should be established as BACT unless the applicant demonstrates, and the permitting authority agrees, that the energy, environmental, or economic impacts justify a conclusion that the most stringent technology is not "achievable" in that case. If the most stringent technology is eliminated in this fashion, then the next most stringent alternative is considered, and so on.

The "top" control option is the use of SF_6 circuit breakers that offer low economic, energy and environmental impacts. SF_6 is the preferred gas for electrical insulation, arc-quenching and current insulation for high voltage equipment. It is chemically inert, non-toxic, non-flammable, non-explosive and thermally stable. SF_6 exhibits properties that are beneficial from an economic, energy and environmental standpoint when used in totally enclosed systems.

Step 5 – Select the BACT

In Step 5 of the BACT determination process, the most effective control option not eliminated in Step 4 should be selected as BACT for the pollutant and emissions unit under review and included in the permit.

BACT

Based on the top-down analysis, the only technically feasible controls technologies for the SF_6 circuit breakers associated with the Project are the use of modern totally enclosed circuit breakers with a leakage rate of 0.5 percent that are thoroughly tested, equipped with leak detection systems (density alarms) and performing periodic inspections. Together these controls will minimize SF_6 fugitive emissions to no more than 13.44 tons CO_2e/year.

SF_6 breakers will be monitored remotely and continuously through the plant control system to confirm that SF_6 integrity is maintained. In the event of an alarm, an inspection will be performed on the breaker. Preventative maintenance will be performed at intervals recommended by the manufacturer or at intervals standard in the electric power industry for the relevant type of breaker. The breaker-specific monitoring program will be submitted after the equipment is selected and placed in service.

3.3.3 Fire Pump Engine

The fire-pump engine is a 300-hp compression-ignition diesel-fired internal combustion engine with a design fuel flow of 16.9 gallons per hour (gal/hr) and a heat input of 2.32 million British thermal units per hour (MMBtu/hr). The maximum CO_2e emissions are less than 20 tons CO_2e/year at the requested hours of operation (100 hours). The gross output and thermal efficiency can be calculated as follows:

- Gross Mechanical Output = Horsepower Rating (300 hp) × Thermal Output Conversion Factor (2,546.4 Btu/hr/hp) = 763,920 Btu/hr
- Thermal Efficiency of Engine = Gross Mechanical Output (763,920 Btu/hr)/Heat Input (2,320,000 Btu/hr) x 100 = 32.9 percent

The fire pump engine is for emergency service and typically operates only a few hours per year for maintenance. In addition, as required by Subpart IIII, the fire pump engine will be operated and maintained according to the manufacturer's emission-related written instructions that are necessary to maintain emissions and efficiency.

The use of a diesel-fired fire pump is the only feasible technology for the Project and it is considered BACT. While natural gas-fired engines and turbines are available for producing electric power, natural gas cannot be stored in sufficient quantity for operation in the event of an emergency, especially if a major fire occurred.

4.0 AIR QUALITY IMPACT ANALYSIS

This section presents an updated air quality impact analysis to confirm the conclusions of the previous air quality analysis associated with the application for PSD permit No. 0110037-011-AC/PSD-FL-423 issued in April 2014. The previous air quality analysis demonstrated compliance with applicable air quality standards. PSD Permit No. 0110037-011-AC/PSD-FL-423 authorized the construction of five nominal 200 MW CTs designated as Units 6A through 6E; however, a CT vendor was not selected. FPL has now selected General Electric 7F.05 CTs for the project and also plans to keep two of the existing 24 GTs (GT Units 1 through 24) for both black start capability and power generation. The black start diesel generators authorized by FDEP in PSD Permit No. 0110037-011-AC/PSD-FL-423 will no longer be part of the Project. Also, the application did not include PSD review for SO_2 and therefore, the previous air quality analysis did not include SO_2. This revised application includes a change in PSD applicability for SO_2, which triggers a PSD review and therefore, also includes an air quality analysis for SO_2. As a result, a revised air quality analysis is performed.

The objectives of the analyses performed in this section are to utilize the latest models, modeling techniques and meteorological data to:

- Update the previous air quality analysis associated with the application for PSD permit No. 0110037-011-AC/PSD-FL-423 issued in April 2014
- Demonstrate compliance with the air quality standards for NO_2, PM_{10}/$PM_{2.5}$, CO, and SO_2

The general modeling approach follows the latest EPA and FDEP modeling guidelines for predicting air quality impacts for regulated pollutants.

While 22 of the 24 GTs will be decommissioned at the Lauderdale Plant as a result of the Project, the air quality impact assessment for the Project considers only the increase in emissions from the five new CTs and does not account for the improvement in the air quality from the decommissioning of 22 of the existing 24 GTs. Similarly, improvement in air quality from the decommissioning of the existing 12 GTs at the Port Everglades Plant is also not accounted for. As a result, the analysis results conservatively reflect the net emissions increase of the overall Project's air quality impact without consideration of the air quality improvements made by retiring most of 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.

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

4.1 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 at nearby areas surrounding the facility. The previous modeling used AERMOD Version 13354. AERMOD Version 14134 is now the most current version and 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.

The 3-km radius surrounding area of the Lauderdale Plant is determined to be rural based on EPA guidance on land use type following the Auer technique and as a result, the rural dispersion option was used in modeling. For modeling analyses that will undergo regulatory review, such as determining compliance with NAAQS, the following model features are recommended by EPA for the 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-Only Sources

Air quality analyses were performed to assess the maximum impacts of the five new simple-cycle CTs at FPL's existing Lauderdale Plant. The CTs being evaluated for the Project are nominal 200 MW GE 7F.05 units.

Summaries of the criteria pollutant emission rates, physical stack and stack operating parameters for the proposed CTs used in the air modeling analysis are presented in Section 2 for both natural gas-firing and

ULSD oil-firing. Impacts were predicted for a range of possible CT operating conditions. The following 9 CT load and temperature scenarios were evaluated when firing natural gas and ULSD oil:

- 100 percent load and ambient temperatures of 35°F, 59°F, and 95°F
- 75 percent load and ambient temperature of 35°F, 59°F, and 95°F
- 50 percent load and ambient temperature of 35°F, 59°F, and 95°F

The new CTs will have stack heights of 87 feet and an inner diameter of 23 ft. 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 Lauderdale Plant's existing sources.

The Project includes a fire pump engine to be installed for emergency purposes only. Operation of this equipment is limited to no more than 100 hr/yr for non-emergency situations. The engine is considered an intermittent source 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 fire pump engine, who agreed that the engine was an intermittent source. Based on the planned intermittent use of the fire pump engine, the emissions from this equipment were not modeled in the air impact assessment.

Building Downwash Effects

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)
CT Air Inlet	72.1	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 Lauderdale-Hollywood International Airport (FLL) and Florida International University (FIU) in Miami, respectively. The 5-year period of the meteorological data was from 2009 through 2013 and was prepared by the FDEP using AERMET Version 14134. 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 4 km (2.5 miles) due east of the Project site. The areas between the airport and Lauderdale Plant are flat with very similar land characteristics. As such, the meteorological parameters collected at Fort Lauderdale-Hollywood International Airport are considered to be representative of those that exist at the Project site.

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	0.62	0.075
Project Site	0.17	0.80	0.205

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

For the significant impact analysis a Cartesian grid was used to predict concentrations on and beyond the property boundary out to 10 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
- From 5 km to 10 km – 1000 meters

More than 3,000 receptors were used to estimate the maximum concentrations predicted for the Project.

Project-Only 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
- SO_2: 1-hour, 3-hour, 24-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 NO_2, 1-hour SO_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 3-hour and 24-hour SO_2, 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, SO_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 represent 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.

A load analysis was first conducted to identify the combination of ambient temperature and operating load condition (i.e., worst-case operating condition). Once the worst-case operating condition was identified, subsequent analyses were performed with the emissions rates and exit gas operating data for those conditions for each pollutant.

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 and 24-hour $PM_{2.5}$ concentrations were predicted to exceed the SIL. When addressing the NAAQS for 1-hour NO_2, the 5-year averages of the 98th (8th 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. For 24-hour $PM_{2.5}$, the 5-year average of the 98th (8th highest) percentile of the 24-hour average concentrations at each receptor are 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), 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 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 background emission sources including the existing FPL Lauderdale Plant sources, and background concentration that accounts for sources not included in the modeling analysis.

For comparison to the allowable 24-hour $PM_{2.5}$ PSD Class II increment, the highest, second-highest concentration is determined.

Background NO_2 Emission Sources

Current EPA guidance on 1-hour NO_2 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 4-1. A detailed list of background sources included in the NAAQS modeling analysis is summarized in Table 4-2. The information in Table 4-2 includes the existing Lauderdale Plant sources and FPL Port Everglades Plant sources.

Background $PM_{2.5}$ Emission Sources

The significant impact area (SIA) for $PM_{2.5}$ was determined to be 3.5 km, which is the maximum distance to which the Project had a predicted significant impact. A 3.5 km distance was used as the basis for determining the inventory of background sources to be included in the air impact analyses.

EPA and FDEP modeling guidance require that the background source inventory include sources located within and 50 km beyond the SIA. Facilities located within the SIA plus 50 km are summarized in Table 4-3. In order to evaluate sources in the screening area that could significantly interact with the Project facilities in the screening area were evaluated using the North Carolina screening technique (also known as the “20D approach”). Based on this technique, facilities whose annual emissions (i.e., TPY) are less than the threshold quantity, Q, are eliminated from the modeling analysis since they are not likely to significantly interact with the Project. Q is equal to 20 × (D − SIA), where D is the distance in km from the facility to the Project site. A summary of detailed source emissions and stack parameters included in the NAAQS and Class II increment analyses is presented in Table 4-4.

Non-Modeled Background Concentrations

The summary of measured ambient concentrations for use in determining background concentrations for $PM_{2.5}$ is presented in Tables 4-5. The background concentrations are based on averages of monitor measurements from 2011 to 2013. The background concentration used for the 24-hour $PM_{2.5}$ NAAQS modeling analysis is 14.7 micrograms per cubic meter (µg/m^3), which is the average of the 98th percentile of maximum daily concentrations for the years 2001, 2012, and 2013.

For compliance demonstrations for the 1-hour NO_2 NAAQS, the use of a uniform background concentration based on the 98th-percentile concentration averaged over a 3-year period often result in overestimations of total NO_2 concentrations in excess of the NAAQS. In such cases, and especially where background emission sources are explicitly included in the modeling analysis, current EPA and FDEP modeling procedures suggest a refinement of the non-modeled background by developing a set of concentrations for each hour of the day and by season from multiple years of hourly monitoring data. The resulting background concentrations are presented in parts per billion (ppb) in Table 4-6. The concentrations presented in Table 4-6 represent calculated 98th percentile concentrations for each hour by season averaged over the 3-year period 2011-2013. For this analysis, no wind direction sectors were excluded. To refine the 1-hour NO_2 modeling results, the 96 concentrations (24 hours x 4 seasons) presented in Table 4-6 were input directly to AERMOD as background concentrations. The predicted 1-hour NO_2 impact for all sources includes the background concentration.

Model Results

Significant Impact/CT Load Analysis

The results of the CT load analysis for emissions equivalent to one CT firing natural gas is presented in Table 4-7 and Table 4-8 presents the CT load analysis results for emissions equivalent to one CT firing ULSD oil. Results for the worst-case load from Table 4-7 and 4-8 were used to predict maximum project-only impacts for emissions equivalent to all five CTs are presented in Table 4-9 and are compared to the significant impact levels. Table 4-10 presents results for the CTs firing either natural gas or ULSD oil for part of the day or year. Based on the results presented in Table 4-9, the proposed project's maximum impacts are predicted to be less than the SIL except for the 1-hour NO_2 and 24-hour $PM_{2.5}$ concentrations. As such, cumulative modeling analyses are required for these pollutants and averaging times to determine compliance with the NAAQS and allowable PSD increments. This conclusion of the significant impact/CT load analysis remains same as the previous air quality analysis.

1-hour NO_2 NAAQS Results

The NAAQS modeling results are summarized in Table 4-10. Using hourly and seasonally varying background concentrations, the maximum predicted total 1-hour concentration is 151.3 µg/m^3 which is less than the NAAQS.

24-Hour $PM_{2.5}$ NAAQS Results

The NAAQS modeling results for 24-hour $PM_{2.5}$ are also summarized in Table 4-10. The maximum predicted 24-hour $PM_{2.5}$ concentration due to all sources is 8.0 µg/m^3, which when added to the background concentration of 14.7 µg/m^3 results in a total concentration of 22.7 µg/m^3, which is less than the NAAQS of 35 µg/m^3.

24-Hour $PM_{2.5}$ Increment Analysis Results

The PSD increment modeling results for 24-hour $PM_{2.5}$ are summarized in Table 4-11. The maximum predicted 24-hour $PM_{2.5}$ increment is 4.5 µg/m^3 which is less than the allowable increment of 9 µg/m^3.

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

Model Selection and General Assumptions

The CALPUFF air modeling system (Version 5.8.4) was used to predict the Project's maximum air quality concentrations at locations beyond 50 km from the Project. The objective of this analysis is to demonstrate that the predicted concentrations for the proposed Project at the Everglades National Park PSD Class I area are consistent with the concentrations presented in the 2013 PSD application. Additional analyses for determining Project-only impacts on air quality related values (AQRVs) and cumulative source modeling to demonstrate compliance with the allowable PSD Class I increments were provided with the original 2013 PSD Application. Because the proposed project has already received an air permit and any revisions to the analyses would not be expected to change significantly, updates to these analyses are not provided.

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 will be used. For ozone background concentrations, observed hourly ozone data for 2001 to 2003 from CASTNET and AIRS stations will be used. A fixed monthly ammonia background concentration of 0.5 ppb will be used.

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.

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 5.8.4 and were originally developed by VISTAS and recompiled for Version 5.8.4 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, SO_2, PM_{10}, and $PM_{2.5}$ concentrations due to the Project were compared to EPA's proposed PSD Class I significant impact levels. The proposed PSD Class I significant impact levels are:

- NO_2: annual average – 0.1 µg/m^3
- SO_2: 3-hour – 1.0 µg/m^3, 24-hour – 0.2 µg/m^3, and 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 4-12 and is consistent with the modeling used to support the the FDEP Air Construction/PSD Permit. The updated modeling indicates maximum concentrations less than the SIL for all pollutants and averaging times except for 24-hour PM_{10} and 24-hour $PM_{2.5}$. Previous modeling conducted with the same emissions determined PSD Increments levels 25 times less than the PSD Increment of 2 $\mu g/m^3$. These results confirm that the air modeling analysis that supported Air Permit No. 0110037-011-AC (PSD-FL-423) does not change the PSD Class I Impacts with the latest information on the GE 7F.05 CT.

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TABLES

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

		Simple Cycle Operation								
		Base Load Turbine Inlet Temperature			75% Load Turbine Inlet Temperature			Low Load Turbine Inlet Temperature		
Parameter	Units	35° F	59° F	95° F	35° F	59° F	95° F	35° F	59° F	95° F
CT Stack Data										
Height	ft	87	87	87	87	87	87	87	87	87
Diameter	ft	23	23	23	23	23	23	23	23	23
Temperature	^oF	1,101	1,086	1,130	1,121	1,152	1,203	1,215	1,215	1,215
Velocity	ft/sec	114.70	114.59	116.39	92.38	93.09	90.22	77.43	77.69	78.70
Maximum Hourly Emissions per Unit										
SO_2	gr/100 cf	2	2	2	2	2	2	2	2	2
	lb/hr	12.40	13.00	13.02	9.76	9.73	9.18	7.52	7.38	7.21
$PM_{10}/PM_{2.5}$	lb/hr	10.60	10.60	10.60	10.60	10.60	10.60	10.60	10.60	10.60
NO_x	ppmvd@15%O2	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00
	lb/hr	72.17	73.81	71.16	56.86	56.63	53.42	43.81	42.95	41.94
CO	ppmvd@15%O2	4.00	4.00	4.00	7.20	7.10	6.90	7.40	7.50	7.70
	lb/hr	19.52	19.97	19.25	27.69	27.19	24.93	21.92	21.79	21.84
VOC (as methane)	ppmvd@15%O2	1.02	0.99	0.97	1.03	1.01	0.97	1.07	1.08	1.08
	lb/hr	3.37	3.39	3.35	2.68	2.64	2.48	2.12	2.12	2.15
Sulfuric Acid Mist	lb/hr	1.90	1.99	1.99	1.50	1.49	1.41	1.15	1.13	1.10

Source: General Electric Company, 2015 (CT Performance Data); Golder, 2015.

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

		Simple Cycle Operation								
		Base Load Turbine Inlet Temperature			75% Load Turbine Inlet Temperature			Low Load Turbine Inlet Temperature		
Parameter	**Units**	**35° F**	**59° F**	**95° F**	**35° F**	**59° F**	**95° F**	**35° F**	**59° F**	**95° F**
<u>CT Stack Data</u>										
Height	ft	87	87	87	87	87	87	87	87	87
Diameter	ft	23	23	23	23	23	23	23	23	23
Temperature	^oF	1,130	1,108	1,143	1,153	1,184	1,215	1,215	1,215	1,215
Velocity	ft/sec	115.34	115.00	116.47	93.47	92.95	90.02	77.09	76.82	75.23
<u>Maximum Hourly Emissions per Unit</u>										
SO_2	%S	0.0015%	0.0015%	0.0015%	0.0015%	0.0015%	0.0015%	0.0015%	0.0015%	0.0015%
	lb/hr	3.57	3.59	3.55	2.82	2.77	2.60	2.19	2.14	2.01
$PM/PM_{10}/PM_{2.5}$	lb/hr	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
NO_x	ppmvd@15%O2	42	42	42	42	42	42	42	42	42
	lb/hr	381.36	380.47	368.66	301.18	295.78	277.64	233.37	227.97	214.53
CO	ppmvd@15%O2	9.00	9.00	9.00	13.70	13.50	13.40	14.04	14.30	14.60
	lb/hr	49.74	49.63	48.09	59.80	57.87	53.92	47.49	47.25	45.39
VOC (as methane)	ppmvd@15%O2	2.12	2.12	2.09	3.89	3.92	3.99	3.88	3.90	3.96
	lb/hr	8.31	8.40	8.32	6.63	6.47	6.15	5.27	5.25	5.14
Sulfuric Acid Mist	lb/hr	0.55	0.55	0.54	0.43	0.42	0.40	0.33	0.33	0.31
Lead	lb/hr	0.033	0.033	0.033	0.026	0.025	0.024	0.020	0.020	0.018

Source: General Electric Company, 2015 (CT Performance Data); Golder, 2015.

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

							Maximum Emissions (tons/year)						
							Operating Scenario	Operating Hours					
							SC-NG 100 % Load	3,390	2,890	2,890	2,890	1,890	2,390
							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	1,000	1,000
	Fuel for Ambient Temperature and Load						SC-ULSD 50 % Load	0	0	0	500	500	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	13.0	3.6	9.7	2.8	7.4	2.1		22.0	19.7	19.5	19.3	16.5	19.2
$PM/PM_{10}/PM_{2.5}$	10.6	50.0	10.6	50.0	10.6	50.0		18.0	27.8	27.8	27.8	27.8	18.0
NO_x	73.8	380.5	56.6	295.8	42.9	228.0		125.1	201.8	180.6	163.7	148.2	109.7
CO	20.0	49.6	27.2	57.9	21.8	47.2		33.8	41.3	43.3	40.7	41.6	34.8
VOC (as methane)	3.4	8.4	2.6	6.5	2.1	5.3		5.8	7.0	6.5	6.2	5.6	5.1
Sulfuric Acid Mist	2.0	0.6	1.5	0.4	1.1	0.3		3.4	3.0	3.0	3.0	2.5	2.9
Lead	0.0	0.033	0.0	0.025	0.0	0.020		0.00	0.01	0.01	0.00	0.00	0.00
Five Combustion Turbines													
SO_2	65.0	18.0	48.7	13.8	36.9	10.7		110	98	97	97	83	96
$PM/PM_{10}/PM_{2.5}$	53.0	250.0	53.0	250.0	53.0	250.0		90	139	139	139	139	90
NO_x	369.1	1902.4	283.1	1478.9	214.7	1139.8		626	1,009	903	818	741	548
CO	99.8	248.1	136.0	289.3	108.9	236.2		169	206	217	203	208	174
VOC (as methane)	17.0	42.0	13.2	32.4	10.6	26.3		28.8	35.0	32.6	31.1	27.9	25.6
Sulfuric Acid Mist	10.0	2.8	7.5	2.1	5.6	1.6		16.9	15.1	14.9	14.8	12.6	14.7
Lead	0.00	0.16	0.00	0.13	0.00	0.10		0.00	0.04	0.03	0.02	0.02	0.00

Source: General Electric Company, 2015; Golder, 2015.

Table 2-4: Performance and Emission Data for the Fire Pump Diesel Engine

Parameter		Units	Fire Pump
Performance			
Number of Units			1
Rating		kW	
Rating		hp	300
Fuel			Diesel
Fuel Heat content (HHV)		Btu/lb	19,500
Fuel density		lb/gal	7.06
Heat input (HHV)		MMBtu/hr	2.37
Fuel usage		gal/hr	17.2
Maximum operation/yr		hours	100
Maximum fuel usage		gal/yr	1,720
Stack Parameters			
Height		ft	17
Diameter		ft	0.8
Temperature		^{o}F	744
Flow		acfm	1,750
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	0.004
		TPY	0.0002
NO_x -	Basis	g/hp-hr	6.8
	Emission rate	lb/hr	4.50
		TPY	0.22
CO -	Basis	g/hp-hr	2.6
	Emission rate	lb/hr	1.72
		TPY	0.09
VOC -	Basis	g/hp-hr	1.0
	Emission rate	lb/hr	0.66
		TPY	0.03
$PM/PM_{10}/PM_{2.5}$ -	Basis	g/hp-hr	0.4
	Emission rate	lb/hr	0.26
		TPY	0.01

Source: FPL, 2013; Golder, 2013.

Emissions 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; 2000 gpm fire pump; 300 ft head, NFPA 20 Certified; Fairbanks Morse Fire Pumps, meeting minimum Subpart IIII NSPS.

Table 2-5: Greenhouse Gas (GHG) Emissions for Combustion Turbine

Pollutant	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)		
	Natural Gas	Distillate Fuel Oil	Natural Gas	ULSD Oil	Natural Gas	USLD Oil	Natural Gas	USLD Oil	Natural Gas	USLD Oil	Natural Gas	Distillate Fuel Oil	Natural Gas	USLD Oil	Total
Natural Gas Only															
CO_2	2,318.6	0.0	118.9	162.3	275,585.9	0.0	3,390	0	467,118.1	0	275,585.9	0.0	467,118.1	0	467,118.1
CH_4	2,318.6	0.0	0.002204	0.006612	5.1	0.0	3,390	0	8.7	0	127.8	0.0	216.5	0	216.5
N_2O	2,318.6	0.0	0.0002204	0.001322	0.5	0.0	3,390	0	0.9	0	152.3	0.0	258.1	0	258.1
										Total	275,865.9	0.0	467,592.7	0.0	467,592.7
Natural Gas & USLD															
CO_2	2,318.6	2,356.2	118.9	162.3	275,585.9	382,384.6	2,890	500	398,221.6	95,596.1	275,585.9	382,384.6	398,221.6	95,596.1	493,817.7
CH_4	2,318.6	2,356.2	0.002204	0.006612	5.1103	15.5795	2,890	500	7.4	3.9	127.8	389.5	184.61	97.37	282.0
N_2O	2,318.6	2,356.2	0.0002204	0.001322	0.5110	3.1159	2,890	500	0.7	0.8	152.3	928.5	220.05	232	452.2
										Total	275,865.9	383,702.6	398,626.3	95,925.7	494,551.9
										Maximum Total			467,592.7	95,925.7	494,551.9

[a] CO_2 based on 40 CFR Part 75 Appendix G, Section 2.3.
CH_4 and N_2O based on Table C-2, Subpart C, 40 CFR 98. Emission factors in lb/MMBtu

Pollutant	Natural Gas	Distillate Fuel Oil
CO_2	118.9	162.3
CH_4	0.002204	0.006612
N_2O	0.0002204	0.0013224

[b] CH_4 and N_2O are multiplied by CO_2e factor

Pollutant	CO_{2e} Factor
CH_4	25
N_2O	298

Table 2-6: Greenhouse Gas (GHG) Emissions for Fire Pump Engine

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
Fire Pump Engine						
CO_2	2.37	163.0	386.0	100	19.3	19.3
CH_4	2.37	0.006612	0.016	100	0.001	0.02
N_2O	2.37	0.001322	0.003	100	0.0002	0.05
						19.4

[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	25
N_2O	298

Table 2-7: Summary of Potential GHG Emissions

	Greenhouse Gases (CO_2e)
Emission Unit Maximum Potential Emissions	
5 CTs[a]	2,472,760
Fire Pump Engine[b]	19.4
Circuit Breakers[c]	12.8
Total:	2,472,792
Netting Calculations	
Potential Emissions - Baseline Actual Emissions	2,472,792
PSD Significant Emission Rate for GHGs	75,000

[a] Based on 3,390 hour/year operation

[b] Based on 100 hour/year operation

[c] 9 Breakers with 25 lb of SF_6 each at 0.5% maximum leakage/yr; GWP of 22,800 lb CO_2e/lb SF_6

Table 2-8: Summary of Maximum Potential Annual Emissions for the Lauderdale CT Project

	Project Maximum Potential Annual Emissions (TPY)					PSD Applicability	
	5		1			PSD Significant Emission Rate	PSD Review Required?
Pollutant	CT [a]	Fire Pump Engine	Fuel Oil Storage Tank	SF_6 Circuit Breakers	TOTAL	(TPY)	
SO_2	110	0.000	NA	NA	110.2	40	YES
PM	139	0.01	NA	NA	139.1	25	YES
PM_{10}	139	0.01	NA	NA	139.1	15	YES
$PM_{2.5}$	139	0.01	NA	NA	139.1	10	YES
NO_x	1,009	0.22	NA	NA	1,009.1	40	YES
CO	217	0.09	NA	NA	216.7	100	YES
VOC (as methane)	35.0	0.03	1.10	NA	36.2	40	NO
Sulfuric Acid Mist	16.9	Neg.	NA	NA	16.9	7	YES
Lead	0.041	Neg.	NA	NA	0.0	0.6	NO
Greenhouse Gases (CO_2e)	2,472,760	19	NA	13	2,472,792	75,000	YES

[a] Based on SC operation for: 3,390 hours (max).

Note: Neg.= negligible; NA= not applicable

Source: Golder, 2015.

Golder Associates

Table 2-9: Summary of Maximum Potential Annual HAP Emissions

Pollutant	Maximum Potential Annual Emissions (TPY) 5 CTs	1 Fire Pump Engine	1 Fuel Oil Storage Tanks	TOTAL	HAP Major Source Threshold (TPY)
Total HAPs	8.7	1.9E-04	NA	8.7	25
Single HAP	3.9 [a]	9.2E-05 [b]	NA	3.9	10

Notes: NA= not applicable.
Emissions of total HAPs from fire pump engine are less than 1/2 pound per year.

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

Source: Golder, 2015

Table 4-1: Summary of the NO_2 Facilities Considered for Inclusion in the Air Modeling NAAQS Analyses

Facility ID	Facility Description	East (km)	North (km)	Relative to Fort Lauderdale 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]									
0110037	FLORIDA POWER & LIGHT (PFL)-FT. LAUDERDALE POWER PLANT	580.2	0.9	0.0	0.0	0.00	0	4,868	YES
0112119	WHEELABRATOR SOUTH BROWARD, INC-WHEELABRATOR SOUTH BROWARD	579.5	2,883.3	-0.8	-0.9	1.15	221	1,497	YES
0112736	G & K SERVICES-G & K SERVICES	581.4	2,883.6	1.1	-0.6	1.24	120	6	NO
0111026	HUMANE SOCIETY OF BROWARD COUNTY-HUMANE SOCIETY OF BROWARD COUNTY	583.3	2,882.8	3.0	-1.4	3.29	115	1	NO
0112141	FLORIDA SILICA SAND COMPANY INC-FLORIDA SILICA SAND COMPANY INC	584.2	2,881.2	3.9	-3.0	4.92	128	1	NO
0112149	FRED HUNTER'S MEMORIAL SERVICES INC-FRED HUNTER MEMORIAL CREMATORY FACILITY	578.6	2,878.7	-1.7	-5.5	5.80	197	ND	NO
0110002	MEMORIAL REGIO HOSP/SO BROWARD HOSP DIST-MEMORIAL REGIO HOSP/SO BROWARD HOSP DIST	581.2	2,877.9	0.9	-6.3	6.33	172	ND	NO
0110054	CITGO PETROLEUM CORP-CITGO - PORT EVERGLADES TERMINAL	586.9	2,885.7	6.6	1.5	6.77	77	8	NO
0110048	MARATHON PETROLEUM COMPANY LP-SPANGLER TERMINAL	587.3	2,885.9	7.0	1.7	7.20	76	ND	NO
0112688	SOUTH FLORIDA MATERIALS CORP. DBA VECENE-VECENERGY - PORT EVERGLADES TERMINAL	587.0	2,885.2	6.7	1.0	6.81	82	10	NO
0110051	BP PRODUCTS NORTH AMERICA, INC.-BP PRODUCTS - PORT EVERGLADES TERMINAL	587.0	2,886.2	6.7	2.0	7.02	73	ND	NO
0110034	HIGH SIERRA TERMINALING, LLC-HIGH SIERRA TERMINALING, LLC	586.2	2,886.5	5.9	2.3	6.28	69	ND	NO
0110036	FLORIDA POWER & LIGHT (PPE)-PORT EVERGLADES POWER PLANT	587.4	2,885.3	7.1	1.1	7.18	81	33,207	YES
0110056	MOTIVA ENTERPRISES LLC-MOTIVA ENTERPRISES - PT. EV. EAST	587.8	2,886.4	7.5	2.2	7.82	74	ND	NO
0110069	TRANSMONTAIGNE TERMINALS, LLC-TRANSMONTAIGNE - NORTH TERMINAL	586.4	2,886.3	6.1	2.1	6.43	71	ND	NO
0110050	MOTIVA ENTERPRISES LLC-MOTIVA ENTERPRISES - SOUTH	586.8	2,884.6	6.5	0.4	6.51	86	10	NO
0110055	MARATHON PETROLEUM COMPANY LP-MARATHON EISENHOWER TERMINAL	587.4	2,886.6	7.1	2.4	7.48	71	ND	NO
0110053	TRANSMONTAIGNE PRODUCT SERVICES INC.-TRANSMONTAIGNE PORT EVERGLADES (SOUTH)	587.1	2,885.6	6.8	1.4	6.94	78	12	NO
0110034	HIGH SIERRA TERMINALING, LLC-HIGH SIERRA TERMINALING, LLC	587.1	2,886.6	6.8	2.4	7.21	71	ND	NO
Beyound Modeling Area (10km - 25km) [a]									
0112078	BROWARD PET CEMETERY INC-BROWARD PET CEMETERY	569.9	2,890.4	-10.4	6.2	12.12	301	ND	NO
0112704	PAS TECHNOLOGIES-PAS TECHNOLOGIES	571.9	2,874.1	-8.4	-10.1	13.14	220	ND	NO
0112146	ATLANTIC BURIAL & CASKET CO-ABCO-FT LAUDERDALE	584.4	2,897.8	4.1	13.6	14.22	17	1	NO
0112152	SCI FUNERAL SERVICES OF FLORIDA INC-GOLD COAST CREMATORY	584.5	2,897.8	4.2	13.6	14.25	17	2	NO
0111019	HOLY CROSS HOSPITAL-HOLY CROSS HOSPITAL	587.1	2,896.5	6.8	12.3	14.07	29	ND	NO
0250603	MIAMI-DADE SOLID WASTE MANAGEMENT-MIAMI DADE SOLID WSTE MGMT/NO DADE LF	570.7	2,872.1	-9.6	-12.1	15.43	219	256	NO
0250664	FLOWERS BAKING COMPANY OF MIAMI, LLC.-FLOWERS BAKING COMPANY OF MIAMI	579.2	2,868.9	-1.1	-15.3	15.37	184	ND	NO
0112183	STIMPSON COMPANY, INC.-STIMPSON COMPANY, INC.	585.5	2,899.5	5.2	15.3	16.16	19	ND	NO
0250407	EXTERIA BUILDING PRODUCTS, LLC.-EXTERIA BUILDING PRODUCTS	577.5	2,867.5	-2.8	-16.7	16.95	190	ND	NO
0250600	MIAMI-DADE WATER AND SEWER DEPARTMENT-NORTH DISTRICT WASTEWATER TREATMNT PLANT	585.3	2,867.1	5.0	-17.1	17.80	164	459	NO
0250624	GENERAL ASPHALT CO., INC.-GENERAL ASPHALT PLANT WDHMA	569.7	2,868.3	-10.6	-15.9	19.10	214	81	NO
0251334	TAURUS INTERNATIONAL MANUFACTURING, INC.-TAURUS INTERNATIONAL	572.1	2,867.0	-8.2	-17.2	19.04	206	5	NO
0110003	W R GRACE & CO-W R GRACE & CO	585.7	2,902.8	5.4	18.6	19.39	16	ND	NO
0251339	AIRCRAFT ELECTRIC MOTORS, INC.-AIRCRAFT ELECTRIC MOTORS, INC.	570.5	2,867.1	-9.8	-17.1	19.68	210	ND	NO
0110038	OLDCASTLE RETAIL, INC.-BONSAL AMERICAN	586.2	2,904.6	5.9	20.4	21.24	16	22	NO
0112357	BROWARD COUNTY WATER/WASTEWATER SERVICES-BROWARD COUNTY/NORTH REGIONAL WWTF	584.1	2,905.0	3.8	20.8	21.15	10	88	NO
0250637	REPUBLIC METALS CORPORATION-REPUBLIC METALS CORPORATION	573.9	2,863.6	-6.4	-20.6	21.61	197	ND	NO
0250593	CORDIS CORP.-CORDIS CORP.	570.3	2,864.9	-10.0	-19.3	21.74	207	ND	NO
0112370	BROWARD CO. WASTE & RECYCLING SERVICES-SOUTHWEST REGIONAL LANDFILL	558.0	2,880.1	-22.3	-4.1	22.66	260	7	NO
7775212	WEEKLEY ASPHALT PAVING, INC.-WEEKLEY ASPHALT PAVING, INC.	557.3	2,880.6	-23.0	-3.6	23.27	261	ND	NO
0112363	MEDIA PRINTING CORPORATION-MEDIA PRINTING CORPORATION	583.9	2,907.1	3.6	22.9	23.16	9	5	NO
0112094	WASTE MANAGEMENT INC. OF FLORIDA-MONARCH HILL	583.2	2,908.0	2.9	23.8	23.98	7	ND	NO
0112410	SOUTH FLORIDA WATER MANAGEMENT DISTRICT-SFWMD PUMP STATION S-9/S-9A	555.9	2,882.2	-24.4	-2.0	24.52	265	161	NO
0112120	WHEELABRATOR NORTH BROWARD, INC.-WHEELABRATOR NORTH BROWARD	583.9	2,907.8	3.6	23.6	23.86	9	1,399	NO
0110005	0-PAVEX DEERFIELD PLANT	584.3	2,908.0	4.0	23.8	24.15	9	ND	NO

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

Fort Lauderdale Facility East and North Coordinates (km) are: 580.3 km 2884.2 km

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

[a] EPA recommends that sources to be modeled are expected to have a significant impact in the modeling area. The "modeling area" is assumed as 10 km per EPA guidance.

[b] Background sources with NO_2 emissions >25 TPY and within 10km of the project location were included in the NAAQS Analysis.

Table 4-2: Summary of NO_2 Sources Included in the NAAQS Modeling Analyses

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 ft/s	Velocity m/s	Stack Parameter Data Source	NO_2 Emission Rate 1-Hour (lb/hr)	1-Hour (g/sec)	Emissions Data Source
0110037	FLORIDA POWER & LIGHT (PFL)-FT. LAUDERDALE POWER PLANT																
	CCCT WITH HRSG (CT 4A) (PHASE II ACID RAIN UNIT)	035	FLCT4A	580167	2883481.1	150.0	45.72	18.0	5.49	330.0	438.7	158.7	48.37		422	53.17	
	CCCT WITH HRSG (CT 4B) (PHASE II ACID RAIN UNIT)	036	FLCT4B	580,168	2,883,508	150.0	45.72	18.0	5.49	330.0	438.7	158.7	48.37	July, 2013 SCA	422	53.17	0110037-005-AV
	CCCT WITH HRSG (CT 5A) (PHASE II ACID RAIN UNIT)	037	FLCT5A	580,168	2,883,546	150.0	45.72	18.0	5.49	330.0	438.7	158.7	48.37		422	53.17	
	CCCT WITH HRSG (CT 5B) (PHASE II ACID RAIN UNIT)	038	FLCT5B	580,168	2,883,546	150.0	45.72	18.0	5.49	330.0	438.7	158.7	48.37		422	53.17	
	Gas Turbine 1		GT1	580243	2883660.7	45.0	13.72	15.6	4.75	860.0	733.2	93.3	28.43		632	79.61	
	Gas Turbine 2		GT2	580245	2883606.1	45.0	13.72	15.6	4.75	860.0	733.2	93.3	28.43		632	79.61	
0112119	WHEELABRATOR SOUTH BROWARD, INC-WHEELABRATOR SOUTH BROWARD																
	863 TPD MSW Combustor & Auxiliary Burners- Units 1 - 3	001-003	WHEEL	579,653	2,883,575	195.0	59.44	7.5	2.29	300	422.0	63.8	19.43	Title V Renewal Application-2010	342	43.09	Title V Renewal Application-2010
0110036	FLORIDA POWER & LIGHT (PPE)-PORT EVERGLADES POWER PLANT																
	Unit 5A nominal 250 MW CTG and HRSG	020	CT1A	587,489	2,885,479	149.0	45.42	22.0	6.71	195	363.7		17.74		19.40	2.444	
	Unit 5B nominal 250 MW CTG and HRSG	021	CT1B	587,443	2,885,477	149.0	45.42	22.0	6.71	195	363.7		17.74	July 2013 SCA	19.40	2.444	January 2012 SCA
	Unit 5C nominal 250 MW CTG and HRSG	022	CT1C	587,349	2,885,474	149.0	45.42	22.0	6.71	195	363.7		17.74		19.40	2.444	

Notes:
All emission rates are based on worst case senario (Firing fuel oil).

Table 4-3: Summary of the $PM_{2.5}$ Facilities Considered for Inclusion in the Air Modeling Analyses

Facility ID	Facility Description	Site	UTM Coordinates East (km)	UTM Coordinates North (km)	Relative to Lauderdale Facility[a] X (km)	Y (km)	Distance (km)	Direction (deg)	Potential $PM_{2.5}$ Emissions (TPY)	Q, (TPY) Emission Threshold [b,c] (Dist - SID) x 20	Include in Modeling Analysis ? [b]
Modeling Area[a]											
0110037	FLORIDA POWER & LIGHT (PFL)	FT. LAUDERDALE POWER PLANT	580.0	2883.5	-0.3	-0.7	0.00	0	424.8	SIA	YES
0112119	WHEELABRATOR SOUTH BROWARD, INC	WHEELABRATOR SOUTH BROWARD	579.6	2883.3	-0.7	-0.9	1.14	220	103.2	SIA	YES
0112736	G & K SERVICES	G & K SERVICES	581.4	2883.6	1.1	-0.6	1.24	120	2.3	SIA	NO
0112076	DAVIE CONCRETE CORPORATION	DAVIE CONCRETE CORPORATION	578.7	2884.5	-1.6	0.3	1.67	281	0.0	SIA	NO
Beyond Modeling Area[a]											
0112074	TRANSFLO TERMINAL SERVICES, INC. (TTSI)	TRANSFLO FORT LAUDERDALE TERMINAL	583.0	2888.7	2.7	4.5	5.25	31	13.5	35.0	NO
0110036	FLORIDA POWER & LIGHT (PPE)	PORT EVERGLADES POWER PLANT	587.4	2,885.3	7.1	1.1	7.18	81	246	73.7	YES
0112127	STEEL FABRICATORS L.L.C.	STEEL FABRICATORS L.L.C.	585.4	2896.0	5.1	11.8	12.79	23	8.7	185.9	NO
0250603	MIAMI-DADE SOLID WASTE MANAGEMENT	MIAMI DADE SOLID WSTE MGMT/NO DADE LF	570.7	2872.1	-9.6	-12.1	15.43	219	4.8	238.7	NO
0112187	CONRAD YELVINGTON DISTRIBUTORS, INC.	CONRAD YELVINGTON DISTRIBUTORS, INC.	584.6	2899.1	4.3	14.9	15.48	16	17.3	239.5	NO
0250407	EXTERIA BUILDING PRODUCTS, LLC.	EXTERIA BUILDING PRODUCTS	577.5	2867.5	-2.8	-16.7	16.95	190	1.3	269.1	NO
0250827	GOODRICH CORPORATION	GOODRICH LANDING SYSTEMS SERVICES	574.5	2867.6	-5.8	-16.6	17.58	199	1.2	281.7	NO
0250600	MIAMI-DADE WATER AND SEWER DEPARTMENT	NORTH DISTRICT WASTEWATER TREATMNT PLANT	585.3	2867.1	5.0	-17.1	17.86	164	5.5	287.1	NO
0112730	R P MINERALS	R P MINERALS	585.7	2901.2	5.4	17.0	17.84	18	18.2	286.7	NO
0251334	TAURUS INTERNATIONAL MANUFACTURING, INC.	TAURUS INTERNATIONAL	572.1	2867.0	-8.2	-17.2	19.04	206	3.4	310.7	NO
0112051	CEMEX CONSTRUCTION MATERIALS FLORIDA LLC	CEMEX-PEMBROKE PINES READY-MIX	562.2	2876.7	-18.1	-7.5	19.61	247	1.0	322.3	NO
0110009	CEMEX CONSTRUCTION MATERIALS FLORIDA LLC	CEMEX NORTH POMPANO FACILITY	586.0	2904.7	5.7	20.5	21.22	16	9.2	354.5	NO
0250637	REPUBLIC METALS CORPORATION	REPUBLIC METALS CORPORATION	573.9	2863.6	-6.4	-20.6	21.61	197	5.6	362.3	NO
0112370	BROWARD CO. WASTE & RECYCLING SERVICES	SOUTHWEST REGIONAL LANDFILL	558.0	2880.1	-22.3	-4.1	22.66	260	1.5	383.1	NO
0250803	PANELFOLD, INC.	PANELFOLD, INC.	572.9	2861.9	-7.4	-22.3	23.50	198	4.5	400.0	NO
0112094	WASTE MANAGEMENT INC. OF FLORIDA	MONARCH HILL	583.2	2908.0	2.9	23.8	23.98	7	33.7	409.5	NO
0112120	WHEELABRATOR NORTH BROWARD, INC.	WHEELABRATOR NORTH BROWARD	583.9	2907.8	3.6	23.6	23.85	9	96.8	407.1	NO
0250258	WHITE ROCK QUARRIES INC	WHITE ROCK QUARRIES-MAIN QUARRY	564.9	2864.8	-15.4	-19.4	24.78	218	37.2	425.6	NO
7775221	RANGER CONSTRUCTION INDUSTRIES, INC.	RANGER CONSTRUCTION, SOUTH - MIAMI #2.	558.1	2868.9	-22.2	-15.3	26.97	235	9.3	469.4	NO
0111024	HANSON ROOF TILE, INC.	HANSON ROOF TILE - DEERFIELD BEACH	584.9	2909.2	4.6	25.0	25.46	10	1.8	439.3	NO
0250378	QUIKRETE MIAMI	QUIKRETE MIAMI	562.0	2863.9	-18.3	-20.3	27.33	222	1.6	476.6	NO
0250022	U S FOUNDRY MANUFACTURING CORP.	U S FOUNDRY MANUFACTURING CORP.	567.3	2859.8	-13.0	-24.4	27.65	208	10.9	482.9	NO
0250615	WASTE MANAGEMENT INC. OF FLORIDA	MEDLEY LANDFILL	565.0	2860.0	-15.3	-24.2	28.59	212	37.1	501.9	NO
0250020	TARMAC AMERICA LLC	TARMAC-PENNSUCO COMPLEX	562.3	2861.7	-18.0	-22.5	28.83	219	73.4	506.7	NO
0250281	MIAMI-DADE WATER AND SEWER DEPARTMENT	HIALEAH/PRESTON WATER TREATMENT PLANT	571.4	2856.9	-8.9	-27.3	28.72	198	21.5	504.4	NO
0250665	H & J ASPHALT, INC.	H & J ASPHALT PLANT	575.1	2855.0	-5.2	-29.2	29.66	190	1.1	523.2	NO
0250005	GENERAL ASPHALT CO., INC.	GENERAL ASPHALT (PLANT #1)	568.8	2855.4	-11.5	-28.8	31.01	202	6.6	550.2	NO
0250348	MIAMI-DADE CO. DEPT. OF SOLID WASTE MGMT	MIAMI-DADE COUNTY RRF/COVANTA	563.8	2857.6	-16.5	-26.6	31.27	212	58.0	555.4	NO
0250232	JACKSON MEMORIAL HOSPITAL	JACKSON MEMORIAL HOSPITAL	578.0	2852.7	-2.3	-31.5	31.54	184	1.3	560.8	NO
0250157	DEPARTMENT OF VETERANS AFFAIRS	VA MEDICAL CENTER	578.6	2852.6	-1.7	-31.6	31.65	183	4.4	562.9	NO
0250608	110TH AVENUE INVESTMENTS, INC.	H & R PAVING	563.8	2852.1	-16.5	-32.1	36.05	207	2.2	651.0	NO
0250476	MIAMI-DADE WATER AND SEWER DEPARTMENT	CENTRAL DISTRICT WASTEWATER TRTMNT PLANT	584.5	2847.8	4.2	-36.4	36.66	173	2.4	663.3	NO
0250006	VULCAN MATERIALS COMPANY	FLORIDA ROCK INDUSTRIES INC DIVISION	559.1	2853.3	-21.3	-30.9	37.48	215	2.1	679.5	NO
0250014	CEMEX CONSTRUCTION MATERIALS FL. LLC.	MIAMI CEMENT PLANT	557.5	2852.0	-22.8	-32.2	39.43	215	314.6	718.6	NO
0990328	HARDRIVES ASPHALT COMPANY	HARDRIVES / DELRAY PLANT	590.6	2923.8	10.3	39.6	40.88	15	7.9	747.6	NO
0250314	MIAMI-DADE WATER AND SEWER DEPARTMENT	ALEXANDER ORR WATER TREATMENT PLANT	568.0	2843.5	-12.3	-40.7	42.52	197	12.9	780.5	NO
0990550	SOUTH FLORIDA WATER MANAGEMENT DISTRICT	SFWMD / PUMP STATION G-335	552.6	2922.0	-27.7	37.8	46.85	324	4.5	867.1	NO
0990095	BETHESDA MEMORIAL HOSPITAL	BETHESDA MEMORIAL HOSPITAL	592.6	2931.9	12.3	47.7	49.29	14	1.7	915.8	NO

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

Fort Lauderdale Facility East and North Coordinates (km) are: 580.30 km 2884.2 km

The significant impact distance for the project is estimated to be: 3.5 km

[a] "Modeling Area" is the area in which the project is predicted to have a significant impact (2 km). All sources within the modeling area with emissions > 5 TPY were included in the analysis.

[b] Sources beyond the modeling areas were included if the emission rate in TPY > Q where Q = Distance x (20-SIA).

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Table 4-4: Summary of $PM_{2.5}$ Sources Included in the NAAQS Modeling Analyses

Facility	Facility Name		Modeling	UTM Location		Stack Parameters								Stack Parameter	$PM_{2.5}$ Emission Rate		Emissions Data
				X	Y	Height		Diameter		Temperature		Velocity			1-Hour		
ID	Emission Unit Description	EU ID	ID Name	(m)	(m)	ft	m	ft	m	°F	K	ft/s	m/s	Data Source	(lb/hr)	(g/sec)	Source
0110037	FLORIDA POWER & LIGHT (PFL)-FT. LAUDERDALE POWER PLANT																
	CCCT WITH HRSG (CT 4A) (PHASE II ACID RAIN UNIT)	035	FLCT4A	580,167	2,883,481	150.0	45.72	18.0	5.49	330.0	438.7	158.7	48.4	Title V Renewal Application-2008	58	7.31	0110037-005-AV
	CCCT WITH HRSG (CT 4B) (PHASE II ACID RAIN UNIT)	036	FLCT4B	580,168	2,883,508	150.0	45.72	18.0	5.49	330.0	438.7	158.7	48.4		58	7.31	
	CCCT WITH HRSG (CT 5A) (PHASE II ACID RAIN UNIT)	037	FLCT5A	580,168	2,883,546	150.0	45.72	18.0	5.49	330.0	438.7	158.7	48.4		58	7.31	
	CCCT WITH HRSG (CT 5B) (PHASE II ACID RAIN UNIT)	038	FLCT5B	580,168	2,883,546	150.0	45.72	18.0	5.49	330.0	438.7	158.7	48.4		58	7.31	
	Gas Turbine 1		GT1	580243	2883660.7	45.0	13.72	15.6	4.75	860.0	733.2	93.3	28.43		8.42	1.06	AP-42, Table 3.1-2a
	Gas Turbine 2		GT2	580245	2883606.1	45.0	13.72	15.6	4.75	860.0	733.2	93.3	28.43		8.42	1.06	AP-42, Table 3.1-2a
0112119	WHEELABRATOR SOUTH BROWARD, INC-WHEELABRATOR SOUTH BROWARD																
	863 TPD MSW Combustor & Auxiliary Burners- Units 1 - 3	001-003	WHEEL	579,653	2,883,575	195.0	59.44	7.5	2.29	300	422.0	63.8	19.43	Title V Renewal Application-2010	103	13.00	0112119-014-AV
0110036	FLORIDA POWER & LIGHT (PPE)-PORT EVERGLADES POWER PLANT																
	Unit 5A nominal 250 MW CTG and HRSG	020	CT1A	587,489	2,885,479	149.0	45.42	22.0	6.71	195	363.7		17.74	January 2012 SCA	13.7	1.73	January 2012 SCA
	Unit 5B nominal 250 MW CTG and HRSG	021	CT1B	587,443	2,885,477	149.0	45.42	22.0	6.71	195	363.7		17.74		13.7	1.73	
	Unit 5C nominal 250 MW CTG and HRSG	022	CT1C	587,349	2,885,474	149.0	45.42	22.0	6.71	195	363.7		17.74		13.7	1.73	

Notes:
All emission rates are based on worst case senario (Firing fuel oil).

Table 4-5: Summary of Maximum Measured $PM_{2.5}$ Concentrations in Vicinity of the FPL Lauderdale Plant, 2011 to 2013

				Concentration (µg/m³)			
				24-Hour			Annual [b]
		Measurement Period			2nd		
Site No.	**Location**	**Year**	**Months**	**Highest**	**Highest**	**98th Percentile [a]**	**Mean**
$PM_{2.5}$ AAQS				**NA**	**NA**	**35**	**12**
012-011-1002	3205 SW 70th Avenue	2013	Jan-Dec	14.9	13.8	13.8	8.0
	Davie, FL	2011	Jan-Dec	28.4	21.8	16.7	6.8
		2010	Jan-Dec	38.5	23.7	13.6	6.5
		3-Yr Average				14.7	7.1

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, 2011-2013.

Table 4-6: Background NO_2 Concentrations for Refined NAAQS Analysis

Hour	3-Year Average 98th-Percentile Concentrations (ppb)			
Ending	Winter	Spring	Summer	Fall
1	39.21	29.59	22.57	28.53
2	38.29	29.87	22.30	26.60
3	34.85	26.12	21.57	25.27
4	34.81	25.18	20.21	24.07
5	32.03	27.66	21.91	24.07
6	32.51	29.72	22.12	25.93
7	32.99	35.15	25.97	29.87
8	35.81	36.36	24.73	32.73
9	37.80	26.48	16.18	27.87
10	29.81	21.85	11.03	22.40
11	19.11	18.17	8.45	17.20
12	21.29	17.36	8.09	15.67
13	22.03	17.93	10.41	15.00
14	20.84	18.97	11.18	17.47
15	24.25	20.78	13.48	20.47
16	21.96	18.08	16.69	17.40
17	21.77	17.69	14.54	15.53
18	22.21	16.51	17.75	15.20
19	27.29	19.48	19.91	19.40
20	27.77	19.27	22.30	21.07
21	31.76	21.90	24.30	23.67
22	36.32	27.03	23.60	26.00
23	33.17	24.85	24.63	28.27
24	35.29	29.69	22.97	27.13

[a]. Dania Monitoring Station (STN ID 012-011-8002), 2011-2013

Note: For NO_2, 1 part per billion (ppb) = 1.881 $\mu g/m^3$

Table 4-7: Maximum Concentrations Predicted for Emissions of One CT Firing Natural Gas in Simple-Cycle Operation, Lauderdale (GE7F.05 Units)

Natural Gas

	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	59°F	95°	35°F	59°F	95°	35°F	59°F	95°	Time	35°F	59°F	95°	35°F	59°F	95°	35°F	59°F	95°
Generic [b]	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	Annual [c]	0.13	0.13	0.12	0.16	0.15	0.16	0.18	0.18	0.18
(10 g/s - 2 g/s/CT)										Annual [d]	0.08	0.08	0.08	0.11	0.11	0.11	0.13	0.13	0.13
										24-Hour [c]	0.93	0.93	0.90	1.18	1.15	1.18	1.38	1.38	1.36
										24-Hour [d]	0.76	0.76	0.74	0.98	0.96	0.98	1.17	1.16	1.15
										8-Hour [c]	2.23	2.24	2.17	2.82	2.77	2.83	3.31	3.29	3.25
										3-Hour [c]	2.48	2.49	2.42	3.10	3.05	3.11	3.63	3.62	3.57
										1-Hour [c]	2.82	2.84	2.75	3.52	3.47	3.53	4.18	4.15	4.06
										1-Hour [e]	2.34	2.35	2.28	2.97	2.92	2.98	3.51	3.50	3.45
Emissions for 1 CT																			
SO_2	12.40	13.00	13.02	9.76	9.73	9.18	7.52	7.38	7.21	Annual [c]	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
										24-Hour [c]	0.14	0.15	0.15	0.14	0.14	0.14	0.13	0.13	0.12
										3-Hour [c]	0.39	0.41	0.40	0.38	0.37	0.36	0.34	0.34	0.32
										1-Hour [e]	0.36	0.38	0.37	0.37	0.36	0.35	0.33	0.33	0.31
PM_{10}	10.60	10.60	10.60	10.60	10.60	10.60	10.60	10.60	10.60	Annual [c]	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
										24-Hour [c]	0.12	0.12	0.12	0.16	0.15	0.16	0.184	0.184	0.181
$PM_{2.5}$	10.60	10.60	10.60	10.60	10.60	10.60	10.60	10.60	10.60	Annual [d]	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.02
										24-Hour [d]	0.10	0.10	0.10	0.13	0.13	0.13	0.16	0.16	0.15
NO_x	72.17	73.81	71.16	56.86	56.63	53.42	43.81	42.95	41.94	Annual [c]	0.11	0.12	0.11	0.11	0.11	0.11	0.10	0.10	0.10
										1-Hour [e]	2.12	2.18	2.04	2.13	2.08	2.01	1.94	1.89	1.82
CO	19.52	19.97	19.25	27.69	27.19	24.93	21.92	21.79	21.84	8-Hour [c]	0.55	0.56	0.53	0.98	0.95	0.89	0.91	0.90	0.89
										1-Hour [c]	0.69	0.71	0.67	1.23	1.19	1.11	1.15	1.14	1.12

[a] Concentrations are based on highest predicted concentrations from AERMOD using five years of meteorological data for 2009 to 2013 consisting of surface and upper air data from the National Weather Service stations at Fort Lauderdale-Hollywood Int'l AP and Florida International University (FIU) in Miami.

[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 5 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 (2009-2013).

[d] Based on highest 5-year average concentration (2009-2013).

[e] Based on highest 5-year average daily maximum 1-hour concentration (2009-2013).

Table 4-8: Maximum Concentrations Predicted for Emissions of One CT Firing ULSD Oil in Simple-Cycle Operation, Lauderdale (GE 7F.05 Units)

Ultra Low-Sulfur Fuel Oil

	Maximum Emission Rates for CT (lb/hr) by Operating Load and Air Temperature										Maximum Predicted Concentrations ($\mu g/m^3$) for CT by Operating Load and Air Temperature [a]								
	Base Load			75% Load			50% Load			Averaging	Base Load			75% Load			50% Load		
	35°F	59°F	95°	35°F	59°F	95°	35°F	59°F	95°	Time	35°F	59°F	95°	35°F	59°F	95°	35°F	59°F	95°
Generic [b]	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	Annual [c]	0.12	0.12	0.12	0.15	0.15	0.16	0.19	0.19	0.19
(10 g/s - 2 g/s/CT)										Annual [d]	0.08	0.08	0.08	0.11	0.11	0.11	0.13	0.13	0.13
										24-Hour [c]	0.91	0.92	0.90	1.15	1.15	1.18	1.39	1.39	1.42
										24-Hour [d]	0.75	0.76	0.74	0.96	0.95	0.98	1.17	1.18	1.21
										8-Hour [c]	2.20	2.22	2.16	2.76	2.75	2.82	3.32	3.33	3.40
										3-Hour [c]	2.45	2.47	2.41	3.04	3.03	3.11	3.65	3.66	3.74
										1-Hour [c]	2.78	2.81	2.74	3.45	3.44	3.53	4.21	4.24	4.40
										1-Hour [e]	2.30	2.32	2.27	2.91	2.90	2.98	3.53	3.54	3.62
Emissions for 1 CT																			
SO_2	3.57	3.59	3.55	2.82	2.77	2.60	2.19	2.14	2.01	Annual [c]	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00
										24-Hour [c]	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
										3-Hour [c]	0.11	0.11	0.11	0.11	0.11	0.10	0.10	0.10	0.09
										1-Hour [e]	0.10	0.11	0.10	0.10	0.10	0.10	0.10	0.10	0.09
PM_{10}	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	Annual [c]	0.08	0.08	0.08	0.10	0.10	0.10	0.12	0.12	0.12
										24-Hour [c]	0.58	0.58	0.57	0.72	0.72	0.74	0.87	0.88	0.90
$PM_{2.5}$	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	Annual [d]	0.05	0.05	0.05	0.07	0.07	0.07	0.08	0.08	0.08
										24-Hour [d]	0.47	0.48	0.46	0.60	0.60	0.62	0.74	0.74	0.76
NO_x	381.4	380.5	368.7	301.2	295.8	277.6	233.4	228.0	214.5	Annual [c]	0.59	0.60	0.57	0.58	0.57	0.55	0.55	0.54	0.52
										1-Hour [e]	11.05	11.14	10.52	11.03	10.81	10.43	10.37	10.16	9.78
CO	49.7	49.6	48.1	59.8	57.9	53.9	47.5	47.2	45.4	8-Hour [c]	1.38	1.39	1.31	2.08	2.00	1.92	1.99	1.98	1.95
										1-Hour [c]	1.74	1.76	1.66	2.60	2.51	2.40	2.52	2.52	2.51

[a] Concentrations are based on highest predicted concentrations from AERMOD using five years of meteorological data for 2009 to 2013 consisting of surface and upper air data from the National Weather Service stations at Fort Lauderdale-Hollywood Int'l AP and Florida International University (FIU) in Miami.

[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 5 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 (2009-2013).

[d] Based on highest 5-year average concentration (2009-2013).

[e] Based on highest 5-year average daily maximum 1-hour concentration (2009-2013).

Table 4-9: Summary of Maximum Concentrations Predicted for Natural Gas and ULSD Oil Firing, Lauderdale (5 GE7F.05 Units)

Pollutant	Averaging Time	Concentrations (µg/m3) Natural Gas Limited to 3390 hrs/yr	Concentrations (µg/m3) Max. 2,890 hrs/yr Natural Gas & Max. 500 Hrs/Yr ULSD Oil[a]	EPA Class II Significant Impact Levels (µg/m3)
SO_2	Annual	0.04	0.04	1
	24-Hour	0.30	0.26	5
	3-Hour	0.79	0.71	25
	1-Hour	0.74	0.66	7.86
PM_{10}	Annual	0.05	0.07	1
	24-Hour	0.92	2.12	5
$PM_{2.5}$	Annual	0.03	0.05	0.3
	24-Hour	0.78	2.04	1.2
Tier 1				
NO_2	Annual	0.23	0.36	1
	1-Hour	10.9	55.7	7.52
Tier 2[b]				
NO_2	Annual	0.17	0.27	1
	1-Hour	8.7	44.6	7.52
CO	8-Hour	4.9	10.4	500
	1-Hour	6.1	13.0	2,000

Maximum Hours of Fuel Usage

Natural Gas	3,390
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.

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Table 4-10: Maximum Predicted 1-hour NO_2 and 24-hour $PM_{2.5}$ Impacts Compared to the NAAQS

Pollutant Averaging Time and Rank	Maximum Concentration (µg/m³)			Receptor Location		NAAQS (µg/m³)
	Total	Modeled Sources[a]	Background	UTM- East (m)	UTM- North (m)	
NO_2 (with background sorted by season and hour-of-day)[a,b]						
1-Hour, 98th Percentile	151.3	-	ıourly by season	578,990	2,883,570	188.1
$PM_{2.5}$						
24-Hour, 98th Percentile	22.7	8.0	14.7	578,990	2,883,570	35

Concentrations are based on concentrations predicted using 5 years of meteorological data from 2009 to 2013 of surface and upper air data from the National Weather Service stations at Fort Lauderdale/Hollywood International Airport and Miami, FL, respectively.

[a] A NO_X to NO_2 converstion factor of 80% applied based on EPA's Guidline on Air Quality Models Tier 2 approach.

[b] based on 98th percentile of seasonal distribution of hour-of-day secific values averaged over 3-years, 2011 - 2013

Table 4-11: Maximum Predicted 24-hour $PM_{2.5}$ Impact from all PSD Sources Compared to the Allowable PSD Class II Increment

Averaging Time and Rank	Maximum Concentration [a] (µg/m³)	Receptor Location UTM- East (m)	Receptor Location UTM- North (m)	Allowable PSD Class II Increment (µg/m³)
24-HR, H2H	4.5	579,690	2,884,170	9

H2H = Highest, Second Highest

[a] Concentrations are predicted using 5 years of meteorological data from 2009 to 2013 with surface and upper air data from the National Weather Service stations at Fort Lauderdale/Hollywood International Airport and Miami, FL, respectively.

Table 4-12: Maximum Pollutant Concentrations at the ENP Compared to the PSD Class I SIL

Pollutant	Averaging Time	Maximum Concentrations[a] at ENP PSD Class I Area (µg/m^3): 3,390 hrs on Nat.Gas	2,890 hrs Nat Gas & 500 Hrs Oil		PSD Class I SIL (µg/m^3)
NO_2	Annual	0.005	0.008	b	0.1
	24-Hour	0.36	1.92	c	--
	8-Hour	0.93	4.88		--
	3-Hour	1.12	6.03		
	1-Hour	1.42	7.49		
SO_2	Annual	0.002	0.001	b	0.1
	24-Hour	0.09	0.03	c	0.2
	8-Hour	0.23	0.07		--
	3-Hour	0.28	0.08		1.0
	1-Hour	0.38	0.10		
PM_{10}	Annual	0.002	0.002	b	0.2
	24-Hour	0.08	0.37	c	0.3
	8-Hour	0.20	0.93		--
	3-Hour	0.24	1.16		
	1-Hour	0.34	1.61		
$PM_{2.5}$	Annual	0.002	0.002	b	0.06
	24-Hour	0.08	0.37	c	0.07
	8-Hour	0.20	0.93		--
	3-Hour	0.24	1.16		
	1-Hour	0.34	1.61		
CO	Annual	0.004	0.005	b	--
	24-Hour	0.20	0.44	c	--
	8-Hour	0.51	1.12		--
	3-Hour	0.62	1.39		
	1-Hour	0.90	1.93		

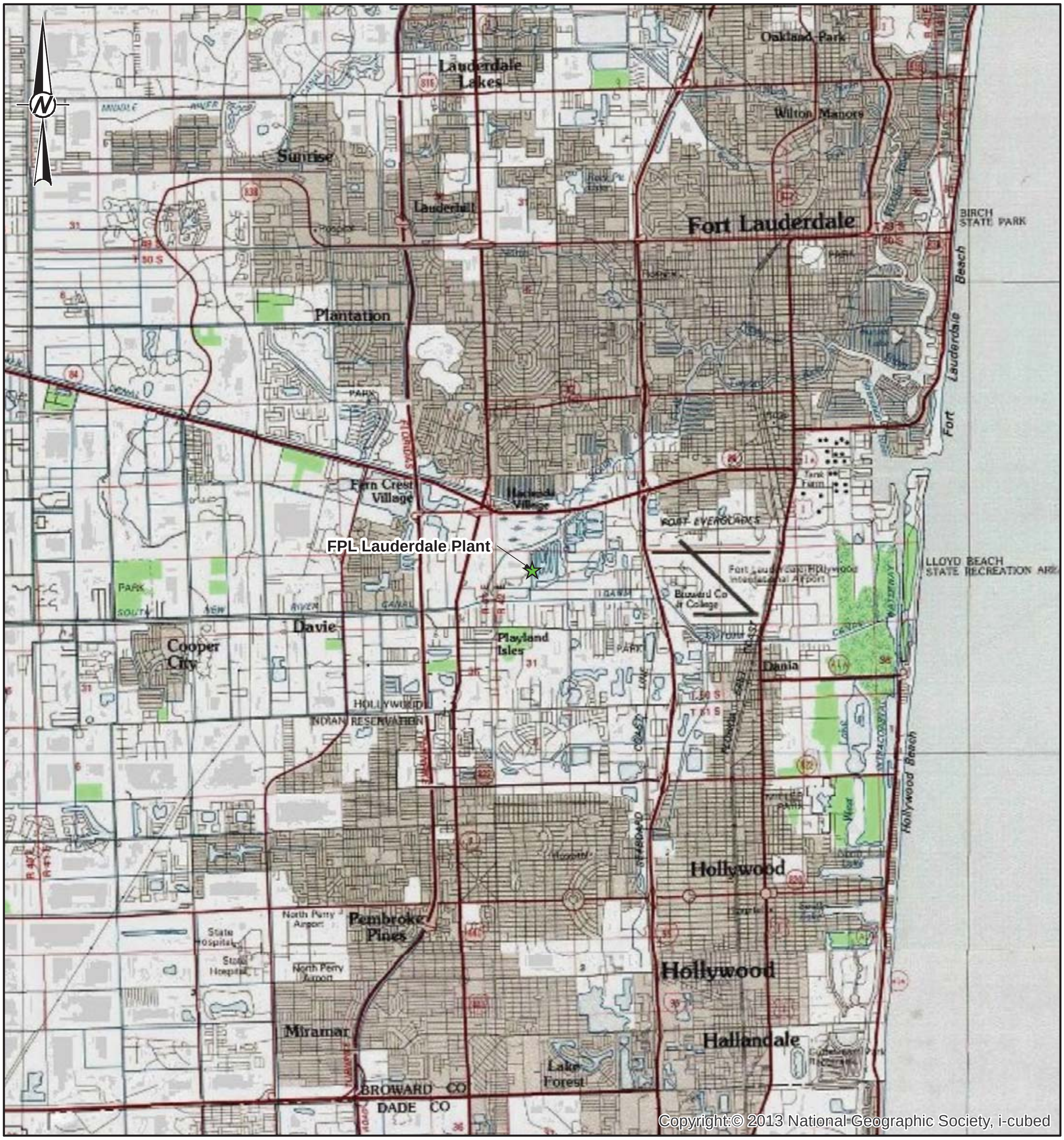
SIL = Class I Significant Impact Level

[a] Concentrations are based on highest predicted concentrations from CALPUFF v5.8.4 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.

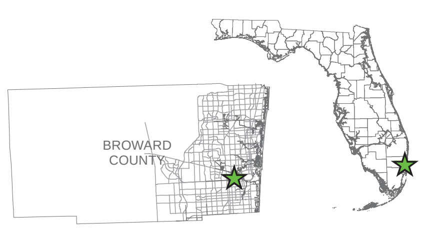
[c] 24-hour concentrations based on 10 hours of fuel oil and 14 hours of natural gas firing.

FIGURES



LEGEND

★ Project Location



0 5,000 10,000 20,000

Feet

REFERENCE(S)

LAUDERDALE PLANT LOCATION, FPL, 2015

CLIENT

FPL

PROJECT

LAUDERDALE PLANT
CT PROJECT

TITLE

LOCATION MAP

CONSULTANT

Golder Associates

YYYY-MM-DD	2015-03-11
DESIGNED	NRL
PREPARED	NRL
REVIEWED	KFK
APPROVED	KFK

PROJECT NO.	CONTROL	REV.	FIGURE
1520938	A006	0	1-1

PATH:

IF THIS MEASUREMENT DOES NOT MATCH WHAT IS SHOWN, THE SHEET SIZE HAS BEEN MODIFIED FROM: ANSI A

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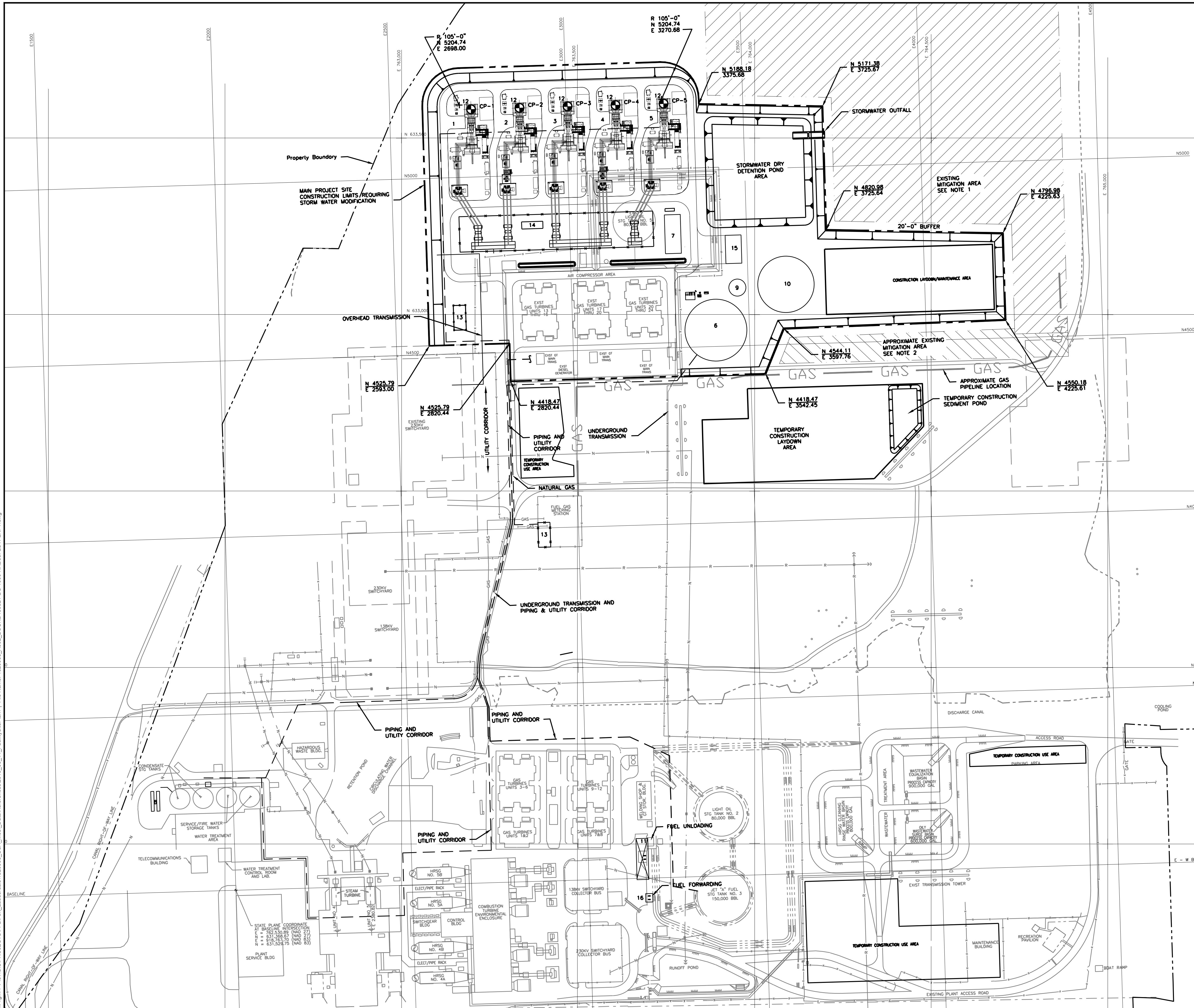

EQUIPMENT IDENTIFICATION LIST

DWG REF	DESCRIPTION	
1	COMBUSTION TURBINE UNIT 6A	
2	COMBUSTION TURBINE UNIT 6B	
3	COMBUSTION TURBINE UNIT 6C	
4	COMBUSTION TURBINE UNIT 6D	
5	COMBUSTION TURBINE UNIT 6E	
6	DEMINERALIZED WATER STORAGE TANK	175 FT DIA X 40 FT H 6,750,000 GAL
7	BLACK START DIESEL GENERATOR	
8	DEMINERALIZED WATER TRAILERS & FORWARDING PUMPS	
9	SERVICE/FIRE WATER TANK	48 FT DIA X 40 FT H 500,000 GAL
10	FUEL OIL STORAGE DOUBLE WALL TANK	160 FT DIA X 40 FT H 3,000,000 GAL
11	FUEL OIL UNLOADING	
12	COMBUSTION TURBINE EXHAUST STACK	23 FT DIA X 80 FT H
13	GAS YARD	
14	CONTROL VAULT	
15	CONTROL ROOM	80 FT X 40 FT x 24 FT H
16	FUEL OIL FORWARDING	

SURVEY CONTROL TABLE

POINT	PLANT GRID		FL 27 STATE PLANE		FL 83 STATE PLANE	
CP-1	N5191.71	E2730.68	N633581.06	E763196.50	N633742.12	E919433.36
CP-2	N5191.71	E2867.68	N633585.10	E763333.44	N633746.16	E919570.30
CP-3	N5191.71	E3003.68	N633589.11	E763469.38	N633750.17	E919706.24
CP-4	N5191.71	E3139.68	N633593.13	E763605.32	N633754.18	E919842.18
CP-5	N5191.71	E3275.68	N633597.14	E763741.26	N633758.19	E919978.12

NOTE(S)

1. MITIGATION AREA TAKEN FROM SURVEY PREPARED BY A.R. TOUSSAINT & ASSOCIATES, INC. LAND SURVEYORS DATED APRIL 15, 1998.
2. APPROXIMATE MITIGATION AREA TAKEN FROM BASSCREEK-PENNSUCO TRANSMISSION LINE MITIGATION ASSESSMENT AREA EXHIBIT 8.

REFERENCE(S)

BASE MAP TAKEN FROM BOUND180321-DS-1000.DWG., REV. 3, DATED 11/MAR/2015 PREPARED BY BLACK & VEATCH.

CLIENT
FPL

PROJECT
LAUDERDALE PLANT
CT PROJECT

TITLE
FACILITY PLOT PLAN

CONSULTANT

Golder Associates

YYYY-MM-DD	2015-03-24
DESIGNED	NRL
PREPARED	NRL
REVIEWED	KFK
APPROVED	KFK

PROJECT NO.	CONTROL	REV.	FIGURE
1520938	A002	1	2-1

Path: \\gnv1-v-fs1\GIS\PROJECTS\FPL\Fort_Lauderdale\1520938_SCA_Mod_Data\References\2015_03_11_FacilitySitePlan\ | File Name: 1520938_A002_BOUND180321-DS-1000-NAD83FLSTPLNFT.dwg

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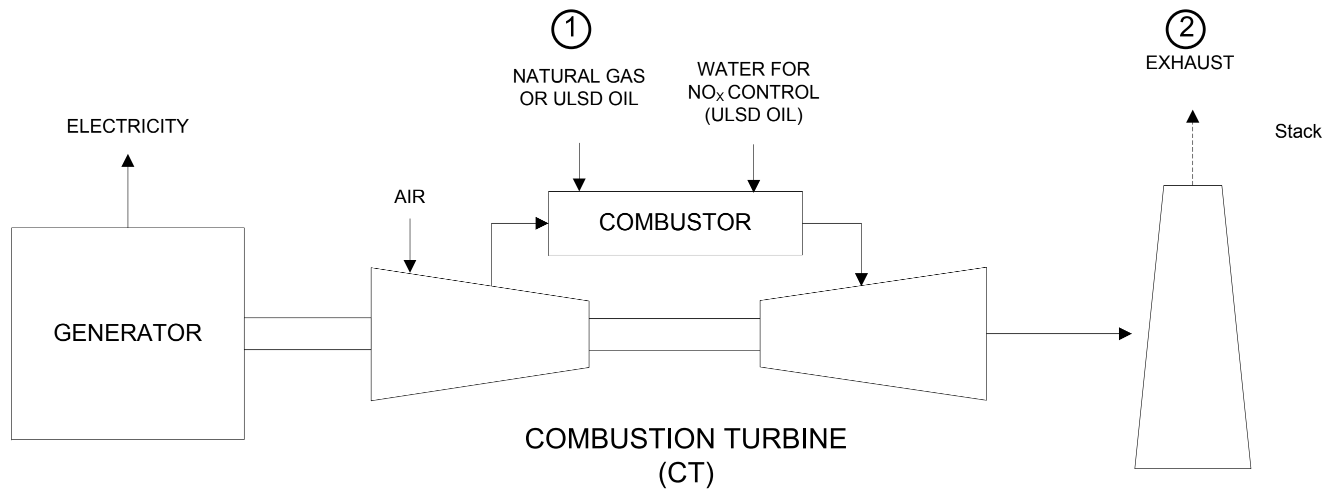
IF THIS MEASUREMENT DOES NOT MATCH WHAT IS SHOWN, THE SHEET SIZE HAS BEEN MODIFIED FROM: ANSI B



	Parameters	Units	Fuel	GE 7F.05
1	CT Heat Input (at 59 °F with inlet cooling)	MMBtu/hr (HHV)	Gas	2,318.6
		MMBtu/hr (HHV)	Oil	2,356.2
2	Mass Flow (at 59 °F with inlet cooling)	lb/hr	Gas	4,272,000
		lb/hr	Oil	4,232,844
2	Stack Velocity	ft/sec	Gas	114.6
		ft/sec	Oil	115.0
2	Stack Temperature	°F	Gas	1,086
		°F	Oil	1,108
2	Stack Height	feet	Gas/Oil	87
2	Stack Diameter	feet	Gas/Oil	23

Figure 2-2. Process Flow Diagram for Each CT
Baseload Operation, Turbine Inlet Temperature of 59°F
FPL Lauderdale CT Project, Broward County, Florida

Source: GE, 2015; Golder, 2015.

Process Flow Legend
Solid/Liquid →
Gas →
Steam →

Golder Associates

APPENDIX A

PERFORMANCE, EMISSION DATA AND CALCULATIONS

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

	CT Only								
	Base Load Turbine Inlet Temperature			75% Load Turbine Inlet Temperature			Low Load Turbine Inlet Temperature		
Parameter	35° F	59° F	95° F	35° F	59° F	95° F	35° F	59° F	95° F
Combustion Turbine Performance									
Heat Input (MMBtu/hr, LHV)	1,992.5	2,089.1	2,091.5	1,568.7	1,563.8	1,474.5	1,208.5	1,185.2	1,158.0
Heat Input (MMBtu/hr, HHV)	2,211.4	2,318.6	2,321.2	1,741.0	1,735.6	1,636.5	1,341.3	1,315.4	1,285.2
Evaporative Cooler/Wet Compression	None	On	On	None	None	None	None	None	None
Fuel heating value (Btu/lb, LHV)	20,566.0	20,566.0	20,566.0	20,566.0	20,566.0	20,566.0	20,566.0	20,566.0	20,566.0
Fuel heating value (Btu/lb, HHV)	22,825	22,825	22,825	22,825	22,825	22,825	22,825	22,825	22,825
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)	4,274,000.0	4,272,000.0	4,186,000.0	3,399,000.0	3,351,000.0	3,127,000.0	2,691,000.0	2,694,000.0	2,713,000.0
Temperature (°F)	1,101.0	1,086.0	1,130.0	1,121.0	1,152.0	1,203.0	1,215.0	1,215.0	1,215.0
Moisture (% Vol.)	7.96	8.94	10.69	7.88	8.59	10.32	7.68	8.16	9.61
Oxygen (% Vol.)	12.39	12.09	11.89	12.47	12.27	11.88	12.69	12.74	12.67
Molecular Weight	28.45	28.19	27.97	28.45	28.38	28.19	28.47	28.41	28.24
Volume flow (acfm)	2,859,223	2,856,529	2,901,328	2,302,999	2,320,705	2,249,148	1,930,341	1,936,574	1,961,972
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)	1,992.5	2,089.1	2,091.5	1,568.7	1,563.8	1,474.5	1,208.5	1,185.2	1,158.0
Heat Content (Btu/lb, LHV)	20,566	20,566	20,566	20,566	20,566	20,566	20,566	20,566	20,566
Fuel Usage (lb/hr)	96,883	101,581	101,696	76,276	76,038	71,696	58,762	57,629	56,307
Heat Content (Btu/cf, LHV)	918	918	918	918	918	918	918	918	918
Fuel Density (lb/ft^3)	0.0446	0.0446	0.0446	0.0446	0.0446	0.0446	0.0446	0.0446	0.0446
Fuel Usage (cf/hr)	2,170,479	2,275,735	2,278,304	1,708,824	1,703,486	1,606,209	1,316,449	1,291,068	1,261,438
CT Stack Parameters									
Stack Height (feet)	87	87	87	87	87	87	87	87	87
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)	1,101	1,086	1,130	1,121	1,152	1,203	1,215	1,215	1,215
Volume flow (acfm)	2,859,223	2,856,529	2,901,328	2,302,999	2,320,705	2,249,148	1,930,341	1,936,574	1,961,972
Diameter (feet)	23	23	23	23	23	23	23	23	23
Velocity (ft/sec)- calculated	114.7	114.6	116.4	92.4	93.1	90.2	77.4	77.7	78.7

Note: Universal gas constant = 1,545.4 ft-lb(force)/°R; atmospheric pressure = 2,116.8 lb(force)/ft² (@14.7 psia).

Source: General Electric Company, 2015; Golder, 2015.

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

	CT Only								
	Base Load Turbine Inlet Temperature			75% Load Turbine Inlet Temperature			Low Load Turbine Inlet Temperature		
Parameter	**35° F**	**59° F**	**95° F**	**35° F**	**59° F**	**95° F**	**35° F**	**59° 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)	0.00479	0.00479	0.00479	0.00609	0.00611	0.00648	0.00790	0.00806	0.00825
Heat Input (MMBtu/hr, HHV)	2,211.4	2,318.6	2,321.2	1,741.0	1,735.6	1,636.5	1,341.3	1,315.4	1,285.2
$PM_{10}/PM_{2.5}$ Emission Rate (lb/hr)	10.6	10.6	10.6	10.6	10.6	10.6	10.6	10.6	10.6
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)	2,170,479	2,275,735	2,278,304	1,708,824	1,703,486	1,606,209	1,316,449	1,291,068	1,261,438
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	13.0	13.0	9.8	9.7	9.2	7.5	7.4	7.2
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 2116.8 lb/ft^2 (pressure) / [1545.4 ft-lb (gas constant, R) x Actual Temp. (°R)] x 60 min/hr									
Basis, ppm actual	10.4	10.6	10.3	10.3	10.4	10.5	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 (%)	7.96	8.94	10.69	7.88	8.59	10.32	7.68	8.16	9.61
Oxygen (%)	12.39	12.09	11.89	12.47	12.27	11.88	12.69	12.74	12.67
Oxygen (%) dry	13.46	13.28	13.31	13.54	13.42	13.25	13.75	13.87	14.02
Flow (acfm)	2,859,223	2,856,529	2,901,328	2,302,999	2,320,705	2,249,148	1,930,341	1,936,574	1,961,972
Flow (acfm), dry	2,631,629	2,601,155	2,591,176	2,121,522	2,121,357	2,017,036	1,782,091	1,778,550	1,773,427
Exhaust Temperature (°F)	1,101	1,086	1,130	1,121	1,152	1,203	1,215	1,215	1,215
NO_x Emission Rate (lb/hr)	72.2	73.8	71.2	56.9	56.6	53.4	43.8	42.9	41.9
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 2116.8 lb/ft^2 (pressure) / [1545.4 ft-lb (gas constant, R) x Actual Temp. (°R)] x 60 min/hr									
Basis, ppm actual	4.64	4.71	4.59	8.28	8.22	8.03	8.28	8.20	8.12
Basis, ppmvd	5.0	5.2	5.1	9.0	9.0	9.0	9.0	8.9	9.0
Basis, ppmvd @ 15% O_2	4.00	4.00	4.00	7.20	7.10	6.90	7.40	7.50	7.70
Moisture (%)	7.96	8.94	10.69	7.88	8.59	10.32	7.68	8.16	9.61
Oxygen (%)	12.39	12.09	11.89	12.47	12.27	11.88	12.69	12.74	12.67
Oxygen (%) dry	13.46	13.28	13.31	13.54	13.42	13.25	13.75	13.87	14.02
Flow (acfm)	2,859,223	2,856,529	2,901,328	2,302,999	2,320,705	2,249,148	1,930,341	1,936,574	1,961,972
Flow (acfm), dry	2,631,629	2,601,155	2,591,176	2,121,522	2,121,357	2,017,036	1,782,091	1,778,550	1,773,427
Exhaust Temperature (°F)	1,101	1,086	1,130	1,121	1,152	1,203	1,215	1,215	1,215
CO Emission Rate (lb/hr)	19.5	20.0	19.3	27.7	27.2	24.9	21.9	21.8	21.8

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

	CT Only								
	Base Load Turbine Inlet Temperature			75% Load Turbine Inlet Temperature			Low Load Turbine Inlet Temperature		
Parameter	**35° F**	**59° F**	**95° F**	**35° F**	**59° F**	**95° F**	**35° F**	**59° 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 2116.8 lb/ft^2 (pressure) / [1545.4 ft-lb (gas constant, R) x Actual Temp. (°R)] x 60 min/hr									
Basis, ppm actual	1.40	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Moisture (%)	7.96	8.94	10.69	7.88	8.59	10.32	7.68	8.16	9.61
Oxygen (%) wet	12.39	12.09	11.89	12.47	12.27	11.88	12.69	12.74	12.67
Oxygen (%) dry	13.46	13.28	13.31	13.54	13.42	13.25	13.75	13.87	14.02
Flow (acfm)	2,859,223	2,856,529	2,901,328	2,302,999	2,320,705	2,249,148	1,930,341	1,936,574	1,961,972
Flow (acfm), dry	2,631,629	2,601,155	2,591,176	2,121,522	2,121,357	2,017,036	1,782,091	1,778,550	1,773,427
Exhaust Temperature (°F)	1,101	1,086	1,130	1,121	1,152	1,203	1,215	1,215	1,215
VOC Emission Rate (lb/hr) as methane	3.37	3.39	3.35	2.68	2.64	2.48	2.12	2.12	2.15
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	13.0	13.0	9.8	9.7	9.2	7.5	7.4	7.2
Conversion to H_2SO_4 (% by weight)	10	10	10	10	10	10	10	10	10
SAM Emission Rate (lb/hr)	1.9	2.0	2.0	1.5	1.5	1.4	1.2	1.1	1.1

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

Source: General Electric Company, 2015, Golder 2015.

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

	CT Only								
	Base Load Turbine Inlet Temperature			75% Load Turbine Inlet Temperature			Low Load Turbine Inlet Temperature		
Parameter	**35° F**	**59° F**	**95° F**	**35° F**	**59° F**	**95° F**	**35° F**	**59° F**	**95° F**
Combustion Turbine Performance									
Heat Input (MMBtu/hr, LHV)	2,196.4	2,211.3	2,183.3	1,735.5	1,703.4	1,599.8	1,345.1	1,314.2	1,236.6
Heat Input (MMBtu/hr, HHV)	2,340.3	2,356.2	2,326.4	1,849.2	1,815.0	1,704.6	1,433.3	1,400.3	1,317.6
Evaporative Cooler/Wet Compression	None	On	On	None	None	None	None	None	None
Fuel heating value (Btu/lb, LHV)	18,459.0	18,459.0	18,459.0	18,459.0	18,459.0	18,459.0	18,459.0	18,459.0	18,459.0
Fuel heating value (Btu/lb, HHV)	19,669	19,669	19,669	19,669	19,669	19,669	19,669	19,669	19,669
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)	4,221,000.0	4,232,844.0	4,162,676.4	3,373,000.0	3,283,000.0	3,102,000.0	2,680,000.0	2,666,000.0	2,595,000.0
Temperature (°F)	1,130.0	1,107.7	1,142.9	1,153.0	1,184.0	1,215.0	1,215.0	1,215.0	1,215.0
Moisture (% Vol.)	10.18	10.83	12.50	10.08	10.70	12.22	9.84	10.22	11.51
Oxygen (% Vol.)	10.92	10.89	10.71	11.03	10.85	10.63	11.27	11.34	11.36
Molecular Weight	28.46	28.22	28.02	28.47	28.40	28.23	28.48	28.43	28.26
Volume flow (acfm)	2,875,216	2,866,864	2,903,527	2,330,001	2,317,113	2,244,082	1,921,775	1,915,098	1,875,310
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)	2,196.4	2,211.3	2,183.3	1,735.5	1,703.4	1,599.8	1,345.1	1,314.2	1,236.6
Heat content (Btu/lb, LHV)	18,459	18,459	18,459	18,459	18,459	18,459	18,459	18,459	18,459
Fuel usage (lb/hr)	118,988	119,796	118,277	94,019	92,280	86,668	72,870	71,196	66,992
CT Stack Parameters									
Stack Height (feet)	87	87	87	87	87	87	87	87	87
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)	1,130	1,108	1,143	1,153	1,184	1,215	1,215	1,215	1,215
Volume flow (acfm)	2,875,216	2,866,864	2,903,527	2,330,001	2,317,113	2,244,082	1,921,775	1,915,098	1,875,310
Diameter (feet)	23	23	23	23	23	23	23	23	23
Velocity (ft/sec)- calculated	115.3	115.0	116.5	93.5	93.0	90.0	77.1	76.8	75.2

Note: Universal gas constant = 1,545.4 ft-lb(force)/°R; atmospheric pressure = 2,116.8 lb(force)/ft² (@14.7 psia).

Source: General Electric Company, 2015; Golder, 2015.

Table GE-A-4: Maximum Emissions for Criteria Pollutants - Simple Cycle Operation (GE 7F.05)
Dry Low NO_x Combustor, ULSD Oil, Base Load

	CT Only								
	Base Load Turbine Inlet Temperature			75% Load Turbine Inlet Temperature			Low Load Turbine Inlet Temperature		
Parameter	**35° F**	**59° F**	**95° F**	**35° F**	**59° F**	**95° F**	**35° F**	**59° 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)	0.02136	0.02122	0.02149	0.02704	0.02755	0.02933	0.03489	0.03571	0.03795
Heat Input (MMBtu/hr, HHV)	2,340.3	2,356.2	2,326.4	1,849.2	1,815.0	1,704.6	1,433.3	1,400.3	1,317.6
PM_{10}/$PM_{2.5}$ Emission Rate (lb/hr)	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
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%	0.0015%	0.0015%	0.0015%
Fuel oil use (lb/hr)	118,988	119,796	118,277	94,019	92,280	86,668	72,870	71,196	66,992
lb SO_2 / lb S (64/32)	2	2	2	2	2	2	2	2	2
SO_2 Emission Rate (lb/hr)	3.57	3.6	3.5	2.82	2.8	2.6	2.19	2.1	2.0
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 2116.8 lb/ft^2 (pressure) / [1545.4 ft-lb (gas constant, R) x Actual Temp. (°R)] x 60 min/hr									
Basis, ppm actual	55.9	55.1	53.9	55.3	55.6	54.9	53.9	52.8	50.8
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 (%)	10.18	10.83	12.50	10.08	10.70	12.22	9.84	10.22	11.51
Oxygen (%)	10.92	10.89	10.71	11.03	10.85	10.63	11.27	11.34	11.36
Oxygen (%) dry	12.16	12.21	12.24	12.27	12.15	12.11	12.50	12.63	12.84
Flow (acfm)	2,875,216	2,866,864	2,903,527	2,330,001	2,317,113	2,244,082	1,921,775	1,915,098	1,875,310
Flow (acfm), dry	2,582,519	2,556,382	2,540,586	2,095,137	2,069,182	1,969,855	1,732,672	1,719,375	1,659,461
Exhaust Temperature (°F)	1,130	1,108	1,143	1,153	1,184	1,215	1,215	1,215	1,215
NO_x Emission Rate (lb/hr)	381.4	380.5	368.7	301.2	295.8	277.6	233.4	228.0	214.5

Table GE-A-4: Maximum Emissions for Criteria Pollutants - Simple Cycle Operation (GE 7F.05)
Dry Low NO_X Combustor, ULSD Oil, Base Load

	CT Only								
	Base Load Turbine Inlet Temperature			75% Load Turbine Inlet Temperature			Low Load Turbine Inlet Temperature		
Parameter	**35° F**	**59° F**	**95° F**	**35° F**	**59° F**	**95° F**	**35° F**	**59° 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 2116.8 lb/ft^2 (pressure) / [1545.4 ft-lb (gas constant, R) x Actual Temp. (°R)] x 60 min/hr									
Basis, ppm actual	11.98	11.82	11.56	18.03	17.88	17.52	18.02	17.99	17.65
Basis, ppmvd	13.3	13.3	13.2	20.0	20.0	20.0	20.0	20.0	20.0
Basis, ppmvd @ 15% O_2	9.0	9.0	9.0	13.7	13.5	13.4	14.0	14.3	14.6
Moisture (%)	10.18	10.83	12.50	10.08	10.70	12.22	9.84	10.22	11.51
Oxygen (%)	10.92	10.89	10.71	11.03	10.85	10.63	11.27	11.34	11.36
Oxygen (%) dry	12.16	12.21	12.24	12.27	12.15	12.11	12.50	12.63	12.84
Flow (acfm)	2,875,216	2,866,864	2,903,527	2,330,001	2,317,113	2,244,082	1,921,775	1,915,098	1,875,310
Flow (acfm), dry	2,582,519	2,556,382	2,540,586	2,095,137	2,069,182	1,969,855	1,732,672	1,719,375	1,659,461
Exhaust Temperature (°F)	1,130	1,108	1,143	1,153	1,184	1,215	1,215	1,215	1,215
CO Emission Rate (lb/hr)	49.7	49.6	48.1	59.8	57.9	53.9	47.5	47.2	45.4
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 2116.8 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	3.50	3.50	3.50	3.50	3.50	3.50
Moisture (%)	10.18	10.83	12.50	10.08	10.70	12.22	9.84	10.22	11.51
Oxygen (%) wet	10.92	10.89	10.71	11.03	10.85	10.63	11.27	11.34	11.36
Oxygen (%) dry	12.16	12.21	12.24	12.27	12.15	12.11	12.50	12.63	12.84
Flow (acfm)	2,875,216	2,866,864	2,903,527	2,330,001	2,317,113	2,244,082	1,921,775	1,915,098	1,875,310
Flow (acfm), dry	2,582,519	2,556,382	2,540,586	2,095,137	2,069,182	1,969,855	1,732,672	1,719,375	1,659,461
Exhaust Temperature (°F)	1,130	1,108	1,143	1,153	1,184	1,215	1,215	1,215	1,215
VOC Emission Rate (lb/hr)	8.31	8.40	8.32	6.63	6.47	6.15	5.27	5.25	5.14
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	3.5	2.8	2.8	2.6	2.2	2.1	2.0
Conversion to H_2SO_4 (% by weight)	10	10	10	10	10	10	10	10	10
SAM Emission Rate (lb/hr)	0.55	0.55	0.54	0.43	0.42	0.40	0.33	0.33	0.31
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)	2,340.3	2,356.2	2,326.4	1,849.2	1,815.0	1,704.6	1,433.3	1,400.3	1,317.6
Emission Rate Basis (lb/10^{12} Btu)	14	14	14	14	14	14	14	14	14
Lead Emission Rate (lb/hr)	0.033	0.033	0.033	0.026	0.025	0.024	0.020	0.020	0.018

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

Source: General Electric Company, 2015; Golder, 2015

Table GE-A-5: Regulated and Hazardous Air Pollutant Emission Factors and Emissions for the Combustion Turbine Firing Gas and Distillate Fuel Oil (GE 7F.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	5 CT
1,3-Butadiene	b,c	4.30E-07	lb/MMBtu	9.97E-04	f,c	1.60E-05	lb/MMBtu	3.77E-02	1.69E-03	1.09E-02	1.09E-02	5.43E-02
Acetaldehyde	b	4.00E-05	lb/MMBtu	9.27E-02		--	--	0.00E+00	1.57E-01	1.34E-01	1.57E-01	7.86E-01
Acrolein	b	6.40E-06	lb/MMBtu	1.48E-02		--	--	0.00E+00	2.52E-02	2.14E-02	2.52E-02	1.26E-01
Benzene	b	1.20E-05	lb/MMBtu	2.78E-02	f	5.50E-05	lb/MMBtu	1.30E-01	4.72E-02	7.26E-02	7.26E-02	3.63E-01
Ethylbenzene	b	3.20E-05	lb/MMBtu	7.42E-02		--	--	0.00E+00	1.26E-01	1.07E-01	1.26E-01	6.29E-01
Formaldehyde	d	1.97E-04	lb/MMBtu	4.57E-01	d	2.15E-04	lb/MMBtu	5.06E-01	7.75E-01	7.87E-01	7.87E-01	3.94E+00
Naphthalene	b	1.30E-06	lb/MMBtu	3.01E-03	f	3.50E-05	lb/MMBtu	8.25E-02	5.11E-03	2.50E-02	2.50E-02	1.25E-01
Polycyclic Aromatic Hydrocarbons (PAH)	b,e	2.20E-06	lb/MMBtu	5.10E-03	f,e	4.00E-05	lb/MMBtu	9.42E-02	8.65E-03	3.09E-02	3.09E-02	1.55E-01
Propylene Oxide	b,c	2.90E-05	lb/MMBtu	6.72E-02		--	--	0.00E+00	1.14E-01	9.72E-02	1.14E-01	5.70E-01
Toluene	b	3.30E-05	lb/MMBtu	7.65E-02		--	--	0.00E+00	1.30E-01	1.11E-01	1.30E-01	6.48E-01
Xylene	b	6.40E-05	lb/MMBtu	1.48E-01		--	--	0.00E+00	2.52E-01	2.14E-01	2.52E-01	1.26E+00
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
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	2.59E-02	0.00E+00	6.48E-03	6.48E-03	3.24E-02
Beryllium		--	--	0.00E+00	g,c	3.10E-07	lb/MMBtu	7.30E-04	0.00E+00	1.83E-04	1.83E-04	9.13E-04
Cadmium		--	--	0.00E+00	g	4.80E-06	lb/MMBtu	1.13E-02	0.00E+00	2.83E-03	2.83E-03	1.41E-02
Chromium		--	--	0.00E+00	g	1.10E-05	lb/MMBtu	2.59E-02	0.00E+00	6.48E-03	6.48E-03	3.24E-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	3.30E-02	0.00E+00	8.25E-03	8.25E-03	4.12E-02
Manganese		--	--	0.00E+00	g	7.90E-04	lb/MMBtu	1.86E+00	0.00E+00	4.65E-01	4.65E-01	2.33E+00
Mercury		--	--	0.00E+00	g	1.20E-06	lb/MMBtu	2.83E-03	0.00E+00	7.07E-04	7.07E-04	3.53E-03
Nickel		--	--	0.00E+00	g,c	4.60E-06	lb/MMBtu	1.08E-02	0.00E+00	2.71E-03	2.71E-03	1.35E-02
Selenium		--	--	0.00E+00	g,c	2.50E-05	lb/MMBtu	5.89E-02	0.00E+00	1.47E-02	1.47E-02	7.36E-02
			Total HAPs =	0.97					1.64	1.61	1.73	8.65
			Max. Individual HAP =	0.46					0.78	0.79	0.79	3.94

[a] Emissions based on:

Fuel	Natural gas	Fuel oil
Heat input (MMBtu/hr) (HHV) (Baseload at 59 °F)	2,319	2,356

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

[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

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

Parameter	**CT at Baseload**					
	Natural Gas-Firing Turbine Inlet Temperature			**ULSD Oil-Firing Turbine Inlet Temperature**		
	35° F	**59° F**	**95° F**	**35° F**	**59° 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	0.106	0.107	0.105	0.121	0.119	0.117
CT, ppmvd @15% O_2	0.091	0.091	0.091	0.091	0.091	0.091
Moisture (%)	7.96	8.94	10.69	10.18	10.83	12.50
Oxygen (%)	12.39	12.09	11.89	10.92	10.89	10.71
Oxygen (%) dry	13.46	13.28	13.31	12.16	12.21	12.24
Exhaust Flow (acfm)	2,859,223	2,856,529	2,901,328	2,875,216	2,866,864	2,903,527
Exhaust Temperature (°F)	1,101	1,086	1,130	1,130	1,108	1,143
Molecular weight	28.45	28.19	27.97	28.46	28.22	28.02
CT Emission rate (lb/hr)	0.451	0.457	0.437	0.511	0.506	0.487
Heat Input (MMBtu/hr, HHV)	2,211	2,319	2,321	2,340	2,356	2,326
CT Emission rate (lb/10^{12} Btu) (HHV)	204.1	197.3	188.5	218.4	214.6	209.1
CT Emission rate (lb/10^6 Btu) (HHV)	2.04E-04	1.97E-04	1.88E-04	2.18E-04	2.15E-04	2.09E-04

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

Source: General Electric Company, 2015 (CT Performance Data); Golder, 2015

Table GE-A-7: Hazardous Air Pollutant Emissions for Fire Pump Engine

Parameter	Units	Value	Annual Emission Basis Fire Pump Engine
Number			1
Heat Input Rate	MMBtu/hr	per unit	2.37
Maximum operation/yr	hours	per unit	100
Heat Input Rate/annual	MMBtu/yr	all units	237
HAPs [Section 112(b) of Clean Air Act]	Emission Factor [a, b]		Emissions (TPY)
Acrolein	lb/MMBtu	7.88E-06	9.33E-07
Acetaldehyde	lb/MMBtu	2.52E-05	2.98E-06
Benzene	lb/MMBtu	7.76E-04	9.19E-05
Formaldehyde	lb/MMBtu	7.89E-05	9.34E-06
Naphthalene	lb/MMBtu	1.30E-04	1.54E-05
Toluene	lb/MMBtu	2.81E-04	3.33E-05
Xylene	lb/MMBtu	1.93E-04	2.29E-05
Acenaphthene	lb/MMBtu	4.68E-06	5.54E-07
Acenaphthylene	lb/MMBtu	9.23E-06	1.09E-06
Anthracene	lb/MMBtu	1.23E-06	1.46E-07
Benzo(a)anthracene	lb/MMBtu	6.22E-07	7.36E-08
Benzo(b)fluoranthene	lb/MMBtu	1.11E-06	1.31E-07
Benzo(k)fluoranthene	lb/MMBtu	2.18E-07	2.58E-08
Benzo(g,h,i)perylene	lb/MMBtu	5.56E-07	6.58E-08
Benzo(a)pyrene	lb/MMBtu	2.57E-07	3.04E-08
Chrysene	lb/MMBtu	1.53E-06	1.81E-07
Dibenzo(a,h)anthracene	lb/MMBtu	3.46E-07	4.10E-08
Fluoanthene	lb/MMBtu	4.03E-06	4.77E-07
Fluorene	lb/MMBtu	4.47E-06	5.29E-07
Indo(1,2,3-cd)pyrene	lb/MMBtu	4.14E-07	4.90E-08
Phenanthrene	lb/MMBtu	1.05E-06	1.24E-07
Pyrene	lb/MMBtu	3.71E-06	4.39E-07
Arsenic	$lb/10^{12}$ Btu	4.0	4.74E-07
Beryllium	$lb/10^{12}$ Btu	3.0	3.55E-07
Cadmium	$lb/10^{12}$ Btu	3.0	3.55E-07
Chromium	$lb/10^{12}$ Btu	3.0	3.55E-07
Lead	$lb/10^{12}$ Btu	9.0	1.07E-06
Mercury	$lb/10^{12}$ Btu	3.0	3.55E-07
Manganese	$lb/10^{12}$ Btu	6.0	7.10E-07
Nickel	$lb/10^{12}$ Btu	3.0	3.55E-07
Selenium	$lb/10^{12}$ Btu	15.0	1.78E-06
Total HAPs =			1.86E-04
Max. Individual HAP =			9.19E-05

[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).

Golder Associates

APPENDIX B

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

Department of
Environmental Protection

Division of Air Resource Management

APPLICATION FOR AIR PERMIT - LONG FORM

I. APPLICATION INFORMATION

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

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

Air Operation Permit – Use this form to apply for:

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

To ensure accuracy, please see form instructions.

Identification of Facility

1. Facility Owner/Company Name: **Florida Power & Light Company**	
2. Site Name: **Lauderdale Plant**	
3. Facility Identification Number: **0110037**	
4. Facility Location... Street Address or Other Locator: **2 Miles West of Ravenswood Road** City: **Ft. Lauderdale** County: **Broward** Zip Code: **33004**	
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) 691-2808** 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:	3. PSD Number (if applicable):
2. Project Number(s):	4. Siting Number (if applicable):

APPLICATION INFORMATION

Purpose of Application

This application for air permit is 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 greenhouse gas (GHG) Prevention of Significant Deterioration (PSD) review associated with the replacement of gas turbines (GTs) at the FPL Fort Lauderdale Plant, and at the FPL Port Everglades Plant, Broward County, Florida. FPL plans to replace the existing 34 simple cycle GTs at these plants with five GE 7F.05 combustion turbines (CTs) that will be rated at approximately 200 MW each (Lauderdale CT Project). The new CTs will be designated as Units 6A through 6E. Please note that references referring to Air Permit Application Report dated July 2013 is associated with FDEP Air Permit No. 0110037-011-AC (PSD-FL-423).

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Processing Fee
Units 6A through 6E	**Five GE 7F.05 Simple-Cycle Combustion Turbines**	**AC1A**	
2	**Circuit Breakers**	**AC1E**	
3	**Diesel Fire Pump Engine**	**AC1E**	

Application Processing Fee

Check one: ☐ Attached - Amount: $________________ ☒ 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 - Lauderdale Plant** 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 4/8/2015 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 ______________________ Date 4/8/15

(seal)

* 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) **580.2** North (km) **2883.3**		2. Facility Latitude/Longitude... Latitude (DD/MM/SS) **26/4/5** Longitude (DD/MM/SS) **80/11/54**	
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: **Dwayne Harper, Plant General Manager**
2. Facility Contact Mailing Address... Organization/Firm: **FPL Lauderdale Plant** Street Address: **4300 SW 42nd Avenue** City: **Fort Lauderdale** State: **FL** Zip Code: **33314**
3. Facility Contact Telephone Numbers: Telephone: **(954) 797-1582** ext. Fax: **(954) 797-1579**
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 will have 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/PM_{10}	**A**	**N**
NO_x	**A**	**N**
CO	**A**	**N**
VOC	**A**	**N**
SO_2	**A**	**N**
Pb	**A**	**N**
SAM	**A**	**N**
HAPS	**A**	**N**
CO_2e	**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:__________ ☒ Previously Submitted, Date: **4/2013** ☐ 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:__________ ☒ Previously Submitted, Date: **4/2013** ☐ Not Applicable (not a CAIR source)

Additional Requirements Comment

Facility "Subject to Regulation" pursuant to 40 CFR 52.21(b)(49)(v)(6).

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:
   Five GE 7F.05 Simple-Cycle CTs.

3. Emissions Unit Identification Number: **Units 6A, 6B, 6C, 6D, and 6E**

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:
A	**2015**	**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 **(Nominal)**

11. Emissions Unit Comment:

Emissions Unit Control Equipment/Method: Control **1** of **2**

1. Control Equipment/Method Description: **Natural Gas: Low NO_x 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 Table GE-A-1 in Appendix A of the PSD report for maximum heat input when firing natural gas and Table GE-A-3 in Appendix A 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 80-ft stack.**		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: **V**	6. Stack Height: **87** feet	7. Exit Diameter: **23** feet
8. Exit Temperature: **See Air Report**	9. Actual Volumetric Flow Rate: **See Air Report**	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 Table GE-A-1 in Appendix A of the PSD report for the stack paramenters associated with each CT when firing natural gas and ultra low sulfur fuel oil, respectively.**		

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: **84.4**	5. Maximum Annual Rate: **42,182**	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 = 18,459 Btu/lb ISO conditions and 5 CTs. Max hourly rate based on 59 F and 500 hours per year operation.**		

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: **11.4**	5. Maximum Annual Rate: **38,574**	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 59 F. Max annual rate based on 59 F and 3,390 hr/yr operation.**		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
CO_2e			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: **Equivalent carbon dioxide - CO_2e**	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): **See Air Report** 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 Table 2-5.**	
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 Table 2-5.**	4. Equivalent Allowable Emissions: **See Table 2-5** lb/hour **See Table 2-5** tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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 _____ 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 Report ☐ 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 Report ☐ 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 Report ☐ 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 Report** ☐ 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

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:
Circuit breakers (nine)

3. Emissions Unit Identification Number: **6**

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:
C	**2015**	**2016**	**49**

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

☐ Acid Rain Unit

☐ CAIR Unit

9. Package Unit:
Manufacturer: **TBD** Model Number: **TBD**

10. Generator Nameplate Rating: MW

11. Emissions Unit Comment:
Nine circuit breakers containing SF6.

<u>Emissions Unit Control Equipment/Method:</u> Control _____ of _____

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

<u>Emissions Unit Control Equipment/Method:</u> Control _____ of _____

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

<u>Emissions Unit Control Equipment/Method:</u> Control _____ of _____

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

<u>Emissions Unit Control Equipment/Method:</u> 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 **100** hours/year
6. Operating Capacity/Schedule Comment:	

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: **F**	6. Stack Height: feet	7. Exit Diameter: Feet
8. Exit Temperature: °F	9. Actual Volumetric Flow Rate: 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:		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment **1** of **1**

1. Segment Description (Process/Fuel Type): **SF6**		
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: **Nine circuit breakers each containing 25 pounds SF6.**		

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
CO_2e			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.

<u>Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions</u>

1. Pollutant Emitted: **Equivalent carbon dioxide - CO_2e**	2. Total Percent Efficiency of Control:
3. Potential Emissions: lb/hour **12.8** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **40 CFR Part 98, Subpart C** Reference: **0.005 percent/year**	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: **See Air Report.**	
11. Potential, Fugitive, and Actual Emissions Comment: **Emissions are for nine circuit breakers.**	

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: **0.005% leakage**	4. Equivalent Allowable Emissions: lb/hour **12.8** tons/year
5. Method of Compliance: **Periodic inspections and leak detection systems.**	
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 _____ of _____

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

Visible Emissions Limitation: Visible Emissions Limitation _____ of _____

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

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 Report** ☐ 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 Report** ☐ 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 Report** ☐ 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: **See Air Report** ☐ 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 Report** ☐ 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

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:

   Diesel fire pump engine for emergency usage.

3. Emissions Unit Identification Number: **6**

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:
C	**2015**	**2016**	**49**

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

   ☐ Acid Rain Unit
   ☐ CAIR Unit

9. Package Unit:
   Manufacturer: **TBD** Model Number: **TBD**

10. Generator Nameplate Rating: MW

11. Emissions Unit Comment:
    One diesel fire pump engine rated at 300 hp. Manufacturer and model number to be determined (TBD).

Emissions Unit Control Equipment/Method: Control 1 of 1

1. Control Equipment/Method Description: **Good combustion practices - No. 2 fuel oil-fired.**	
2. Control Device or Method Code: **N/A**	

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.)

<u>Emissions Unit Operating Capacity and Schedule</u>

1. Maximum Process or Throughput Rate:	
2. Maximum Production Rate:	
3. Maximum Heat Input Rate: **2.32** 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 **100** hours/year
6. Operating Capacity/Schedule Comment: **The diesel fire pump engine will normally be operated 1 to 2 hours per month for testing and maintenance. The fire pump engine will meet the requirements of 40 CFR 60 Subpart IIII.**	

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: **17** feet	7. Exit Diameter: **0.8** Feet
8. Exit Temperature: **744**°F	9. Actual Volumetric Flow Rate: **1,750** 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 Table 2-6.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment **1** of **1**

1. Segment Description (Process/Fuel Type): **Diesel fuel combustion**		
2. Source Classification Code (SCC):	3. SCC Units: **1,000 gallons**	
4. Maximum Hourly Rate: **0.017**	5. Maximum Annual Rate: **1.72**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.0015**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **137.7**
10. Segment Comment: **Maximum annual rate based on 100 hr/yr operation.**		

Segment Description and Rate: Segment _____ of _____

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

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
CO_2e			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.

<u>Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions</u>

1. Pollutant Emitted: **Equivalent carbon dioxide - CO_2e**	2. Total Percent Efficiency of Control:
3. Potential Emissions: lb/hour **19.4** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **40 CFR Part 98, Subpart C** Reference: **GHG from combustion**	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: **See Table 2-6.**	
11. Potential, Fugitive, and Actual Emissions Comment: **Emissions are for one engine.**	

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 Table 2-6.**	4. Equivalent Allowable Emissions: lb/hour **19.4** tons/year
5. Method of Compliance: **Fuel use records.**	
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: **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.**	

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 Report ☐ 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 Report ☐ 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 Report ☐ 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: See Air Report ☐ 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 Report** ☐ 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